YEAR ENDING 2009

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PUBLIC SERVICE
COMMISSION

ANNUAL REPORT
OF

NorthWestern Energy

GAS UTILITY

TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

Gas Annual Report

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Sch. 1	IDENTIFICATION	
	Legal Name of Respondent:	NorthWestern Corporation
	Name Under Which Respondent Does Business:	NorthWestern Energy
	Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912
		Natural Gas - Jan 01, 1933
		Propane - Oct 13, 1995
	Person Responsible for Report:	Kendall G. Kliewer
	Telephone Number for Report Inquiries:	(406) 497-2759
	Address for Correspondence Concerning Report:	40 East Broadway Street
		Butte, MT 59701

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity:

N/A

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	See Northwestern Corporation's Annual Report on Form 10-K	
3	to the SEC for the Corporate Board of Directors.	
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Sch. 3

OFFICERS

Title	Department Supervised	Name
President & Chief Executive Officer	Executive	Robert Rowe
Vice President,	Tax, Internal Audit, Credit	Brian Bird
Chief Financial Officer and Treasurer	Financial Planning and Analysis	
	Controller and Treasury Functions	
	Investor Relations and Business Development	
	Cash Management and Financial Applications	
	Information Technology	
	Energy Risk Management	
	Flight Services, Executive Compensation	
Interim General Counsel &	Legal Services	Tim Olson
Corporate Secretary	Corporate Secretary	
	Records Management	
	Risk Management	
Vice President,	Retail Operations - MT/SD/NE	Curt Pohl
Retail Operations	Construction, Asset Management	
	Organizational Development & Labor Relations	
	Large Project Development	
	Safety/Health/Environmental Services	
	Support Services	
Vice President,	Transmission and Supply Compliance	David Gates
Wholesale Operations	Energy Supply	
	Production and Generation	
Vice President,	Government & Regulatory Affairs	Patrick Corcoran
Government & Regulatory Affairs		
Vice President,	Corporate Communications	Bobbi Schroeppel
Customer Care, Communications &	Account and Analysis	
Human Resources	Systems and Support	
	Revenue Collection, Customer Interaction	
	Key Accounts/Customer Education	
	Human Resources	
Chief Audit & Compliance Officer	Internal Audit	Michael Nieman
	Enterprise Risk	
Vice President, Controller	Financial Reporting	Kendall Kliewer
	Accounting	
	Accounts Payable/Payroll	
	Compensation and Benefits	

Reflects active officers as of April 24, 2010.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		$ 74,202	101.07%
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility (including CU4) Natural Gas Utility Natural Gas Pipeline (including CMP) Propane Utility Natural Gas Funding Trust - (Bond Transition Financing) 1/		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		$ (782)	-1.07%
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management		
Clarkfoot and Blackfoot, LLC	Milltown hydroelectric facility		
NorthWestern Investments, LLC	Holds non-utility assets		
Risk Partners Assurance, Ltd.	Captive insurance company		
Mountain States Transmission Intertie, LLC	Will hold new transmission infrastructure assets		
Indirect Subsidiaries:			
Montana Generation, LLC	Non-regulated energy marketing		
Total Corporation		**$ 73,420**	**100.00%**

1/ While the Natural Gas Funding Trust (the Trust) is regulated by the MPSC and information pertaining to the Trust is reported to the MPSC on a semi-annual basis, it is reflected on the equity basis in this presentation.

Sch. 5

CORPORATE ALLOCATIONS

	Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
	Controller	Includes the following departments: Controller, Accounting Accounts Payable, Payroll, Financial Reporting and Compensation & Benefits	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	$38,273,500	85.99%	$6,235,318
	Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE CC MT, Business Develop, Corp Communications & Contributions, Human Resources and Print Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	18,837,676	74.17%	6,560,559
	Legal Department	Includes the following departments: Chief Legal, Record Services, Risk Mgmt	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	15,162,086	87.95%	2,077,128
	Finance	Includes the following departments: CFO, Treasury, FP&A Tax , Investor Relations, Corporate Aircraft, IT CS, IT Applications Infrastructure, Licensing & Leasing and Capital Related Exp.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	13,933,113	74.11%	4,868,627
	Regulatory and Gov't Affairs	Includes the following departments: Regulatory Affairs, Load Research, Government Affairs, Reg Support Services, Community Relations & Public Affairs.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	3,441,276	83.82%	664,376
	Executive Department	Includes the following departments: CEO	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	2,611,983	70.87%	1,073,416
	Audit & Controls	Includes the following departments: Audit and Controls, Enterprise Risk Management Internal Audit	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	791,631	73.00%	292,795
	Retail Operations	Includes the following departments: Sioux Falls Facilities and Mail Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	482,144	73.00%	178,327
#REF!	TOTAL			$93,533,409	80.99%	$21,950,546

Sch. 6	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Rev.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6						
7						
8						
9	**Total Nonutility Subsidiaries**			$0		$0
10	**Total Nonutility Subsidiaries Revenues**			$0		
11						
12						
13	**Utility Subsidiaries**					
14	Canadian-Montana Pipeline Corporation	Transportation	Tariff Rates	$28,800	33.6%	$28,800
15	**Total Utility Subsidiaries**			$28,800		$28,800
16	**Total Utility Subsidiaries Revenues**			$2,422,506		
17	**TOTAL AFFILIATE TRANSACTIONS**			$28,800		$28,800

Sch. 7 — AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6						
7						
8						
9	**Total Nonutility Subsidiaries**			$0		$0
10	**Total Nonutility Subsidiaries Expenses**			$168,472		
11						
12						
13	**Utility Subsidiaries**					
14	Natural Gas Funding Trust	Metering and billing services	Negotiated Contract Rate	$1,000,000	95.8%	$1,000,000
15	**Total Utility Subsidiaries**			$1,000,000		$1,000,000
16	**Total Utility Subsidiaries Expenses**			$1,067,814		
17	TOTAL AFFILIATE TRANSACTIONS			$1,000,000		$1,000,000

Sch. 8	MONTANA UTILITY INCOME STATEMENT - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	LastYear Montana	% Change
1						
2	400 Operating Revenues	$ 347,751,918	$ 115,350,393	$ 232,401,525	$ 293,261,767	-20.75%
3						
4	**Total Operating Revenues**	347,751,918	115,350,393	232,401,525	293,261,767	-20.75%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	267,104,666	99,134,841	167,969,825	215,002,529	-21.88%
9	402 Maintenance Expense	7,134,943	1,499,918	5,635,025	5,306,369	6.19%
10	403 Depreciation Expense	16,964,064	5,184,110	11,779,954	11,227,311	4.92%
11	404-405 Amort. & Depletion of Gas Plant	2,319,211	425,331	1,893,880	1,495,535	26.64%
12	406 Amort. of Plant Acquisition Adj.	(2,288,552)	(2,288,552)	-	-	-
13	407.3 Regulatory Amortizations - Debit	9,276,458	2,550,323	6,726,135	10,046,857	-33.05%
14	407.4 Regulatory Amortizations - Credit	(4,712,373)	(831,238)	(3,881,135)	(1,452,277)	-167.24%
15	408.1 Taxes Other Than Income Taxes	23,226,593	1,682,946	21,543,647	21,919,141	-1.71%
16	409.1 Income Taxes-Federal	(4,707,733)	(2,360,200)	(2,347,533)	5,725,834	-141.00%
17	-Other	(543,873)	(254,480)	(289,393)	718,973	-140.25%
18	410.1 Deferred Income Taxes-Dr.	17,377,712	7,040,653	10,337,059	14,134,905	-26.87%
19	411.1 Deferred Income Taxes-Cr.	(9,520,189)	(3,075,083)	(6,445,106)	(12,397,097)	48.01%
20	411.4 Investment Tax Credit Adj.	(37,582)	(37,582)	-	-	-
21						
22	**Total Operating Expenses**	321,593,345	108,670,987	212,922,358	271,728,080	-21.64%
23	**NET OPERATING INCOME**	$ 26,158,573	$ 6,679,406	$ 19,479,167	$ 21,533,687	-9.54%

This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, in accordance with FERC requirements, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana Pipeline Corporation.

Sch. 9	MONTANA REVENUES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Core Distribution Business Units**					
3	**(DBUs)**					
4	440 Residential	$ 193,579,244	$ 60,993,045	$ 132,586,199	$ 161,392,590	-17.85%
5	442.1 Commercial	113,842,467	47,326,260	66,516,207	81,261,800	-18.15%
6	442.2 Industrial Firm	1,650,341	-	1,650,341	2,406,178	-31.41%
7	445 Public Authorities	526,121	-	526,121	671,947	-21.70%
8	448 Interdepartmental Sales	477,153	-	477,153	589,300	-19.03%
9	491.2 CNG Station	-	-	-	-	-
10						
11	**Total Sales to Core DBUs**	310,075,326	108,319,305	201,756,021	246,321,815	-18.09%
12						
13	447 Sales for Resale	7,864,869	-	7,864,869	23,215,388	-66.12%
14						
15	**Total Sales of Natural Gas**	7,864,869	-	7,864,869	23,215,388	-66.12%
16		0				
17	**Transportation**					
18						
19	489 Transportation (inc. CMP)	26,034,367	6,351,733	19,682,634	19,343,244	1.75%
20	495 Off System Storage	80,901	-	80,901	-	-
21						
22	**Total Revenues From Transportation**	26,115,268	6,351,733	19,763,535	19,343,244	2.17%
23						
24	**Other Operating Revenue**					
25						
26	Miscellaneous Revenues	3,696,455	679,355	3,017,100	4,381,320	-31.14%
27						
28	**Total Other Operating Revenue**	3,696,455	679,355	3,017,100	4,381,320	-31.14%
29	**TOTAL OPERATING REVENUE**	$ 347,751,918	$ 115,350,393	$ 232,401,525	$ 293,261,767	-20.75%
30						
31						
32	Sales for Resale reported on line 13 represents on and off-system sales from excess supply.					
33	Revenues generated from these sales flow back to customers as a credit to gas cost expense.					
34	This line consists of sales for resale and sales to other utilities, as compared to Schedule 35,					
35	which only reflects sales to other utilities.					
36						
37						

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Gas Raw Materials**					
2	**Gas Raw Materials-Operation**					
3	728 Liquefied Petroleum Gas	$ -	$ -	$ -	$ -	-
4	735 Miscellaneous Production Expenses	153	153	-	-	-
5	**Total Operation-Gas Raw Materials**	153	153	-	-	-
6						
7	**Gas Raw Materials-Maintenance**					
8	741 Structures & Improvements	19,626	19,626	-	-	-
9	**Total Maintenance-Gas Raw Materials**	19,626	19,626	-	-	-
10	**Total Gas Raw Materials**	19,779	19,779	-	-	-
11	**Production Expenses**					
12						
13	**Production & Gathering-Operation**					
14	750 Supervision & Engineering	-	-	-	-	-
15	751 Maps & Records	-	-	-	-	-
16	752 Gas Wells Expenses	-	-	-	-	-
17	753 Field Lines Expenses	-	-	-	-	-
18	754 Field Compressor Station Expense	-	-	-	-	-
19	755 Field Comp. Station Fuel & Power	-	-	-	-	-
20	756 Field Meas. & Reg. Station Expense	-	-	-	-	-
21	757 Dehydration Expense	-	-	-	-	-
22	758 Gas Well Royalties	-	-	-	-	-
23	759 Other Expenses	-	-	-	-	-
24	760 Rents	-	-	-	-	-
25	**Total Oper.-Production & Gathering**	-	-	-	-	-
26						
27	**Other Gas Supply Expense-Operation**					
28	800 NG Wellhead Purchases	97,503,162	-	97,503,162	176,082,157	-44.63%
29	803 NG Transmission Line Purchases	839,473	-	839,473	470,452	78.44%
30	805 Other Gas Purchases	82,983,190	84,382,296	(1,399,106)	5,762,998	-124.28%
31	805 Purchased Gas Cost Adjustments	-	-	-	-	-
32	805 Incremental Gas Cost Adjustments	-	-	-	-	-
33	805 Deferred Gas Cost Adjustments	-	-	-	-	-
34	806 Exchange Gas	-	-	-	-	-
35	807 Well Expenses-Purchased Gas	2,793,120	13,110	2,780,010	1,612,368	72.42%
36	807 Purch. Gas Meas. Stations-Oper.	-	-	-	-	-
37	807 Purch. Gas Meas. Stations-Maint.	-	-	-	-	-
38	807 Purch. Gas Calculations Expenses	-	-	-	-	-
39	808 Other Purchased Gas Expenses	-	-	-	-	-
40	808 Gas Withdrawn from Storage -Dr.	22,729,322	-	22,729,322	(4,285,657)	>300.00%
41	809 Gas Delivered to Storage -Cr.	-	-	-	-	-
42	810 Gas Used-Comp. Station Fuel-Cr.	-	-	-	-	-
43	811 Gas Used-Products Extraction-Cr.	-	-	-	-	-
44	812 Gas Used-Other Utility Oper.-Cr.	-	-	-	-	-
45	813 Other Gas Supply Expenses	-	-	-	-	-
46	**Total Other Gas Supply Expenses**	206,848,267	84,395,406	122,452,861	179,642,318	-31.84%
47	**Total Production Expenses**	206,848,267	84,395,406	122,452,861	179,642,318	-31.84%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	This Year Montana	% Change
1	**Storage Expenses**					
2						
3	**Underground Storage-Operation**					
4	814 Supervision & Engineering	44,437	-	44,437	22,295	99.32%
5	815 Maps & Records	505	-	505	227	121.79%
6	816 Wells	245,999	-	245,999	204,987	20.01%
7	817 Lines	41,395	-	41,395	51,128	-19.04%
8	818 Compressor Station	370,552	-	370,552	340,336	8.88%
9	819 Compressor Station Fuel & Power	-	-	-	-	-
10	820 Measuring & Regulating Station	55,860	-	55,860	43,190	29.34%
11	821 Purification	109,701	-	109,701	79,853	37.38%
12	824 Other Expenses	100,862	-	100,862	104,246	-3.25%
13	825 Storage Well Royalties	87,483	-	87,483	186,112	-52.99%
14	826 Rents	-	-	-	-	-
15	**Total Operation-Underground Storage**	1,056,794	-	1,056,794	1,032,374	2.37%
16						
17	**Underground Storage-Maintenance**					
18	830 Supervision & Engineering	70	-	70	-	-
19	831 Structures & Improvements	29,115	-	29,115	56,566	-48.53%
20	832 Reservoirs & Wells	7,707	-	7,707	13,108	-41.21%
21	833 Lines	11,758	-	11,758	12,184	-3.50%
22	834 Compressor Station Equipment	185,827	-	185,827	212,590	-12.59%
23	835 Meas. & Reg. Station Equipment	1,185	-	1,185	634	86.84%
24	836 Purification Equipment	17,935	-	17,935	8,680	106.62%
25	837 Other Equipment	8,953	-	8,953	7,288	22.84%
26	**Total Maintenance-Underground Storage**	262,549	-	262,549	311,050	-15.59%
27	**Total Underground Storage Expenses**	1,319,343	-	1,319,343	1,343,424	-1.79%
28	**Transmission Expenses**					
29	**Transmission-Operation**					
30	850 Supervision & Engineering	2,280,013	-	2,280,013	1,973,634	15.52%
31	851 System Control & Load Dispatching	962,052	-	962,052	897,794	7.16%
32	853 Compressor Station Labor & Expense	600,834	-	600,834	504,823	19.02%
33	855 Other Fuel & Power for Comp. Stat.	-	-	-	-	-
34	856 Mains	967,087	-	967,087	903,969	6.98%
35	857 Measuring & Regulating Station	590,090	-	590,090	566,856	4.10%
36	858 Transmission & Comp.-By Others	-	-	-	-	-
37	859 Other Expenses	1,243,039	-	1,243,039	1,415,086	-12.16%
38	860 Rents	-	-	-	-	-
39	**Total Operation-Transmission**	6,643,115	-	6,643,115	6,262,162	6.08%
40	**Transmission-Maintenance**					
41	861 Supervision & Engineering	212,131	-	212,131	74,377	185.21%
42	862 Structures & Improvements	88,541	-	88,541	75,309	17.57%
43	863 Mains	196,071	-	196,071	318,538	-38.45%
44	864 Compressor Station Equipment	385,567	-	385,567	441,690	-12.71%
45	865 Meas. & Reg. Station Equipment	273,340	-	273,340	353,773	-22.74%
46	867 Other Equipment	20,072	-	20,072	12,344	62.60%
47	**Total Maintenance-Transmission**	1,175,722	-	1,175,722	1,276,031	-7.86%
48	**Total Transmission Expenses**	7,818,837	-	7,818,837	7,538,193	3.72%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Distribution Expenses**					
2	**Distribution-Operation**					
3	870 Supervision & Engineering	2,882,417	1,212,075	1,670,342	1,372,805	21.67%
4	871 Load Dispatching	100,803	100,803	-	-	-
5	872 Compressor Station Labor & Expense	-	-	-	-	-
6	873 Compressor Station Fuel and Power	-	-	-	-	-
7	874 Mains and Services	4,020,775	1,917,836	2,102,939	2,083,335	0.94%
8	875 Meas. & Reg. Station-General	368,628	188,245	180,383	187,361	-3.72%
9	876 Meas. & Reg. Station-Industrial	-	-	-	-	-
10	877 Meas. & Reg. Station-City Gate	195,379	46,679	148,700	116,204	27.96%
11	878 Meter & House Regulator	2,300,785	764,770	1,536,015	1,581,835	-2.90%
12	879 Customer Installations	2,700,295	229,339	2,470,956	2,422,933	1.98%
13	880 Other Expenses	2,388,614	383,191	2,005,423	643,845	211.48%
14	881 Rents	2,343	-	2,343	1,353	73.15%
15	**Total Operation-Distribution**	14,960,039	4,842,938	10,117,101	8,409,671	20.30%
16	**Distribution-Maintenance**					
17	885 Supervision & Engineering	1,079,250	287,988	791,262	650,389	21.66%
18	886 Structures & Improvements	938	938	-	-	-
19	887 Mains	1,289,165	348,424	940,741	640,653	46.84%
20	889 Meas. & Reg. Station Exp.-General	167,430	119,172	48,258	50,906	-5.20%
21	890 Meas. & Reg. Station Exp.-Industrial	-	-	-	-	-
22	891 Meas. & Reg. Station Exp.-City Gate	56,193	56,193	-	-	-
23	892 Services	874,372	346,450	527,922	515,629	2.38%
24	893 Meters & House Regulators	1,125,694	274,853	850,841	723,084	17.67%
25	894 Other Equipment	-	-	-	-	-
26	**Total Maintenance-Distribution**	4,593,042	1,434,018	3,159,024	2,580,661	22.41%
27	**Total Distribution Expenses**	19,553,081	6,276,956	13,276,125	10,990,332	20.80%
28	**Customer Accounts Expenses**					
29	**Customer Accounts-Operation**					
30	901 Supervision	-	-	-	-	-
31	902 Meter Reading	1,221,245	713,924	507,321	477,595	6.22%
32	903 Customer Records & Collection	3,251,069	546,843	2,704,226	2,607,531	3.71%
33	904 Uncollectible Accounts	1,256,077	423,835	832,242	1,147,925	-27.50%
34	905 Miscellaneous Customer Accounts	53,820	53,849	(29)	(39)	25.71%
35	**Total Customer Accounts Expenses**	5,782,211	1,738,451	4,043,760	4,233,012	-4.47%
36						
37	**Customer Service & Information Expenses**					
38	**Customer Service-Operation**					
39	907 Supervision	-	-	-	-	-
40	908 Customer Assistance	2,407,353	1,107,387	1,299,966	1,341,619	-3.10%
41	909 Inform. & Instructional Advertising	513,501	117,326	396,175	321,852	23.09%
42	910 Misc. Customer Service & Inform.	-	-	-	-	-
43	**Total Customer Service & Information Exp.**	2,920,854	1,224,713	1,696,141	1,663,471	1.96%
44					468,348	
45	**Sales Expenses**					
46	**Sales-Operation**					
47	911 Supervision	-	-	-	-	-
48	912 Demonstrating & Selling	-	-	-	-	-
49	913 Advertising	114,017	44,196	69,821	159,616	-56.26%
50	916 Miscellaneous Sales	-	-	-	-	-
51	**Total Sales Expenses**	114,017	44,196	69,821	159,616	-56.26%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana		% Change
1	**Administrative & General Expenses**					
2	**Admin. & General - Operation**					
3	920 Administrative & General Salaries	12,162,616	3,425,429	8,737,187	8,607,119	1.51%
4	921 Office Supplies & Expenses	3,358,886	1,182,360	2,176,526	2,151,603	1.16%
5	922 Administrative Exp. Transferred-Cr.	(1,466,866)	77,931	(1,544,797)	(2,153,515)	28.27%
6	923 Outside Services Employed	2,369,594	514,419	1,855,175	1,380,301	34.40%
7	924 Property Insurance	299,378	73,728	225,650	168,559	33.87%
8	925 Legal & Claim Department	4,317,230	697,666	3,619,564	1,722,369	110.15%
9	926 Employee Pensions & Benefits	2,687,085	419,969	2,267,116	(1,775,436)	227.69%
10	928 Regulatory Commission Expenses	69,918	25	69,893	98,273	-28.88%
11	930 Miscellaneous General Expenses	4,109,790	237,251	3,872,539	2,776,315	39.48%
12	931 Rents	871,585	260,206	611,379	624,317	-2.07%
13	**Total Operation-Admin. & General**	28,779,216	6,888,984	21,890,232	13,599,905	60.96%
14	**Admin. & General - Maintenance**				-	
15	935 General Plant	1,084,004	46,274	1,037,730	1,138,627	-8.86%
16	**Total Admin. & General Expenses**	29,863,220	6,935,258	22,927,962	14,738,532	55.56%
17	**TOTAL OPER. & MAINT. EXPENSES**	$ 274,239,609	$ 100,634,759	$ 173,604,850	$ 220,308,898	-21.20%
18						
19						
20						
21						
22						

Sch. 11	MONTANA TAXES OTHER THAN INCOME - NATURAL GAS (INCLUDES CMP)			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$1,603,559	$1,564,646	2.49%
3	Property Taxes	18,694,524	18,642,350	0.28%
4	Crow Tribe RR and Utility Tax	67,248	73,024	-7.91%
5	Blackfoot Possessoray Tax	287,088	281,880	1.85%
6	City Tax	535	2,592	-79.36%
7	Consumer Counsel	144,823	261,538	-44.63%
8	Public Service Commission	526,984	695,523	-24.23%
9	Heavy Highway Use	5,209	6,125	-14.96%
10	Vehicle Use Taxes	78,627	77,218	1.82%
11	Oil & Gas Royalty Taxes	113,584	256,257	-55.68%
12	Delaware Franchise Tax	-	36,480	-100.00%
13				
14				
15				
16	**Canadian Taxes**			
17	Ad Valorem	21,466	21,508	-0.20%
18				
19				
20				
21				
22	**TOTAL TAXES OTHER THAN INCOME**	$21,543,647	$21,919,141	-1.71%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	360NETWORKS (USA) INC	Network Services	96,690
2	ADVENTURE DIVERS INC	Barge Delivery Services	183,733
3	ALCO OIL & GAS PRODUCTION	Engineering and Fabrication Services	343,169
4	ALME CONSTRUCTION, INC.	Welding Services	315,634
5	AMERICAN INNOVATIONS INC	Software Licensing Fees	123,842
6	ARCADIS	Engineering Services	980,339
7	AREVA T&D ENERGY	Software Support Services	432,255
8	AREVA T&D INC	Software Support Services	266,065
9	ASPLUNDH TREE EXPERT CO	Tree Trimming	3,250,786
10	ASSOCIATED ARBORISTS	Vegetation Management	524,780
11	AUTOMOTIVE RENTALS INC	Fleet Management	6,732,547
12	B & B CONTRACTING INC	Construction	147,218
13	BALHOFF WILLIAMS LLC	Legal Services	640,591
14	BART ENGINEERING COMPANY	Engineering Services	214,926
15	BILL FIELD TRUCKING INC	Equipment Transportation	344,594
16	BISON ENGINEERING INC	Engineering Services	76,434
17	BONDHOLDER COMMUNICATIONS GROUP	Settlement Support Services	123,522
18	BRANDENBURG INDUSTRIAL SERVICE	Construction	109,600
19	BROWNING, KALECZYC, BERRY & HOVEN	Legal Services	398,558
20	CA INC	Software Maintenance Agreements	77,394
21	CARDINAL UTILITY CONSTRUCTION	Construction	293,259
22	CENTRAL AIR SERVICE INC	Aerial Pilot Services	387,915
23	CENTRAL COPTERS INC	Flight Services	131,980
24	CENTRON SERVICES INC	Collection Services	92,036
25	CESSNA AIRCRAFT COMPANY	Aircraft Maintenance	328,028
26	CINC LLC	Strategic Consulting and Government Relations	111,029
27	CLEM WILLIAMS & DATSOPOULOS	Legal Services	120,000
28	CONTINENTAL STEEL WORKS	Fabrication Services	930,013
29	CON-WAY TRANSPORTATION SERVICES	Freight Services	108,734
30	CREST KROGH & NORD LLC	Legal Services	102,953
31	CURTIS, MALLET-PREVOST, COLT & MOSLE LLP	Legal Services	468,767
32	DAVENPORT, EVANS, HURWITZ & SMITH, LLP	Legal Services	82,074
33	DAVEY TREE SURGERY COMPANY	Tree Trimming	713,207
34	DELOITTE & TOUCHE LLP	Audit Services	1,490,969
35	DEVLIN ENTERPRISES	Professional Services	75,604
36	DEWILD GRANT RECKERT & ASSOCIATES CO.	Engineering Services	106,831
37	DICKSTEIN SHAPIRO LLP	Legal Services	1,969,875
38	DIGITAL INSPECTIONS - A KEMA COMPANY	Computer Licensing	354,330
39	DISTRIBUTION CONSTRUCTION CO	Gas Pipeline Construction	224,235
40	DJ&A P.C. CONSULTING ENGINEERS	Engineering Services	118,303
41	DNV GLOBAL ENERGY CONCEPTS	Engineering Services	81,744
42	DOWL HKM	Professional Services	176,240
43	EDISON ELECTRIC INSTITUTE	Membership Dues	205,000
44	EDM INTERNATIONAL INC	Anchor Rod Inspection Services	83,596
45	EDWARDS JET CENTER	Charter Services	77,726
46	EIDE BAILLY	Audit Services	83,104
47	EIM ENERGY INSURANCE MUTUAL	Insurance Premiums	505,000
48	ELM LOCATING & UTILITY SERVICE	Locating Services and Excavation Notifications	1,984,747
49	EMC CORPORATION HEADQUARTERS	Software Support Services	122,635
50	ENERGY SHARE OF MONTANA	USBC Services	746,447
51	EXEC AIR MONTANA INC	Flight Services	77,908
52	FACTORY MUTUAL INSURANCE COMPANY	Insurance Premiums	805,271
53	FAEGRE & BENSON LLP	Legal Services	299,215
54	FAIRBANKS MORSE ENGINE	Construction	82,608
55	FALLS CONSTRUCTION COMPANY	Construction	263,626
56	FISHNET SECURITY	Software Support Services	635,531
57	FITCH INC	Debt Rating Services	145,000
58	GARTNER GROUP INC	IT Consulting	103,000
59	GILLESPIE PRUDHON & ASSOCIATES	Engineering Services	97,379
60	GLACIER ELECTRIC COOPERATIVE	Engineering Services	133,055
61	GRANT THORNTON LLP	Audit/Accounting Services	141,639
62	GREAT DIVIDE ENERGY CONSULTING	Energy Consulting	105,781
63	GREENE ESPEL P.L.L.P.	Legal Services	80,127
64	H & H CONTRACTING INC	Concrete Services	107,022

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
65	HAIDER CONSTRUCTION INC	Backhoe Services	192,349
66	HARRINGTON'S FLOOR COVERING INC	Carpet Installation Services	76,255
67	HARTELCO INC	Boring Services	101,361
68	HAYS COMPANIES	Insurance Premiums	2,311,273
69	HDR ENGINEERING INC	Engineering Services	347,580
70	HEATH CONSULTANTS INC	Gas Leak Surveys	401,197
71	HIGH MARK MEDIA	Marketing Service	86,189
72	INDEPENDENT INSPECTION COMPANY	Electric Line Inspection	1,184,219
73	INDEPENDENT POWER SYSTEMS INC	Installation of Renewal Energy Systems	219,602
74	INFRASOURCE UNDERGROUND	Construction	220,584
75	INTEGRATED DESKTOP SOLUTIONS INC	Drafting Services	161,720
76	INTERGRAPH CORPORATION	Software Consultants	99,466
77	ITRON	Hardware and Software Maintenance	639,741
78	JACOBSEN TREE EXPERTS	Tree Trimming	234,608
79	JOHNSON HEIDEPRIEM ABDALLAH AND JOHNSON LLP	Legal Services	190,000
80	JONES DAY	Legal Services	404,654
81	JSSI JET SUPPORT SERVICES INC	Flight Services	141,219
82	KEMA SERVICES INC	USB and DSM Programs and Services	7,520,494
83	KM CONSTRUCTION CO INC	Concrete Services	173,643
84	LANDMARK AVIATION -FSD	Charter Services	84,483
85	LANDS ENERGY CONSULTING	Energy Consultants	120,415
86	LARSON DIGGING INC	Construction	137,201
87	LC STAFFING SERVICE	Temporary Employment Services	338,466
88	LEONARD,STREET & DEINARD	Legal Services	534,009
89	LIEN TRANSPORTATION CO	Transportation Services	139,412
90	LOGAN SIMPSON DESIGN INC	Environmental Consulting	174,031
91	MANAGEMENT APPLICATIONS CONSULTING	Rate Case Consulting	159,906
92	MAPPCOR	Electric Reliability Services	202,171
93	MARSH USA INC	Consulting - Risk Management	119,597
94	MERCER HUMAN RESOURCE CONSULTING	Actuarial and Consulting Services	159,651
95	MERIDIAN IT INC	IT Services	168,540
96	MICHAEL J HANSON	Legal Consulting	90,079
97	MICROSOFT LICENSING GP	Computer Licensing	981,811
98	MILLS CONSTRUCTION INC	Construction	815,425
99	MONTANA-DAKOTA UTILITIES CO	Joint Trenching Services	114,996
100	MOODY'S INVESTORS SERVICE	Professional Services	191,250
101	MOODY'S KMV	Credit Professionals Fees	129,527
102	MOUNTAIN POWER CONSTRUCTION CO	Construction	384,441
103	MTS TESTING GROUP	Inspection Services	161,418
104	NATIONAL CENTER FOR APPROPRIATE TECHNOLOGY	Lab testing	1,449,361
105	NEWMECH COMPANIES INC	Construction	14,424,774
106	NEXANT INC	Energy Consulting	448,680
107	NORDIC DEVELOPMENT INC	Concrete Services	117,600
108	NORTHWEST ENERGY EFFICIENCY	Energy Services	309,661
109	OLSON LAND SERVICES	Professional Services	135,172
110	OPEN ACCESS TECHNOLOGY INT'L INC	Software Support Services	286,553
111	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	3,361,685
112	PAUL HASTINGS, JANOFSKY & WALKER LLP	Legal Services	128,296
113	PAUL, WEISS, RIFKIND, WHARTON & GARRIS	Legal Services	267,989
114	PAULSEN MARKETING	Advertising	1,310,633
115	PBS&J	Land and Permitting Services	1,810,263
116	PICEK CONSTRUCTION CO INC	Construction	540,757
117	PONDERA ENGINEERS	Engineering Services	332,148
118	POWER ENGINEERS INCORPORATED	Engineering Services	2,284,945
119	PRO PIPE SERVICES INC	Pipeline Fabrication Services	526,645
120	PROFESSIONAL MAILING & MARKETING	Mailing Services	2,825,879
121	RML INCORPORATED	Boring Services	132,346
122	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	8,813,506
123	ROD TABBERT CONSTRUCTION INC	Construction	240,500
124	ROUNDS BROTHERS TRENCHING	Boring Services	84,478
125	SAP AMERICA INC	Software Maintenance	2,064,417
126	SCENIC CITY ENTERPRISES INC	Hydro Evacuation Services	240,989
127	SIME CONSTRUCTION	Construction	99,927
128	SMARTPROS LEGAL & ETHICS LTD	HR Consulting	94,318
129	SMARTPROS LTD	HR Consulting	116,113

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
130	SMITTY'S PLUMBING & HEATING INC	Plumbing Services	87,954
131	SOLAR PLEXUS	USB and DSM Programs and Services	121,046
132	SOUTH DAKOTA ELECTRIC UTILITY	Membership Dues	91,356
133	SPHERION CORPORATION	Temporary Employment Services	85,409
134	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	350,105
135	STINSON MORRISON HECKER LLP	Legal Services	102,776
136	STONE & WEBSTER CONSULTANTS	Power Generation Development	427,741
137	STONE & WEBSTER INC	Power Generation Development	1,490,943
138	SULLIVAN, TABARACCI & RHOADES, PC	Legal Services	113,638
139	SUNDANCE SOLAR SYSTEMS	Installation of Renewal Energy Systems	130,075
140	TERRACON	Engineering Services	260,033
141	THE CLARO GROUP LLC	Health Insurance Consulting	108,868
142	THE ELECTRIC COMPANY	Construction	226,771
143	THE ENERGY AUTHORITY INC	Scheduling and Dispatching	479,159
144	THE L E MYERS CO	Storm Damage Restoration	1,017,308
145	THE LIBERTY CONSULTING GROUP	Professional Services	83,755
146	THOMAS KNAPP	Legal Services	86,283
147	THRIVE INC	HR Consulting	104,828
148	TODD BRUESKE CONSTRUCTION	Construction	388,123
149	TONY LASLOVICH CONSTRUCTION	Construction	222,401
150	TOWER SYSTEMS INC	Construction	437,381
151	TP CONSTRUCTION INCORPORATED	Construction	133,760
152	TRADEMARK ELECTRIC INC	Electrical Contractors	407,622
153	UTILITIES UNDERGROUND LOCATION	Locating Services and Excavation Notifications	112,982
154	VARSITY CONTRACTORS INC	Janitorial Services	254,644
155	VERTEX	Billing Services	3,250,677
156	WALKER CONSTRUCTION INC	Construction	150,967
157	WASHINGTON FORESTRY CONSULTANT	Forestry Consultants	168,243
158	WINSTON & STRAWN LLP	Legal Services	818,361
159	WRIGHT AND SUDLOW, INC.	Concrete Services	95,695
160	WRIGHT TREE SERVICE INC	Tree Trimming	306,079
161	YAK & ABE CONSTRUCTION	Concrete Services	76,616
162	ZACHA UNDERGROUND CONSTRUCTION	Construction	86,166
163	**Total of Payments Set Forth Above**		**$ 105,374,606**

1/ This schedule includes payments for professional services over $75,000.

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
1				
2	NorthWestern Energy does not make any			
3	contributions to Political Action Committees (PACs) or			
4	candidates. The company may contribute to ballot			
5	issue campaigns in accordance with various state			
6	laws.			
7				
8	There are three employee PACs:			
9				
10	a. Employees of NorthWestern Corporation			
11	(NorthWestern Energy) PAC;			
12				
13	b. NorthWestern Energy Employees PAC; and			
14				
15	c. NorthWestern Public Service Employees PAC.			
16				
17	All of the money contributed by members is			
18	dedicated to support political candidates. No			
19	company funds may be spent in support of a			
20	political candidate. Nominal administrative costs			
21	for such things as duplicating, postage, and meeting			
22	expenses are paid by the company as provided by			
23	law. These costs are charged to shareholder			
24	expense.			
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	**TOTAL Contributions**	$ -	$ -	-

Sch. 14	Pension Costs 1/			
1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: ________		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$ 339,249,764	$ 327,143,594	3.70%
8	Service cost	7,410,909	7,517,814	-1.42%
9	Interest cost	20,786,204	19,934,599	4.27%
10	Plan participants' contributions	-	-	-
11	Amendments	-	48,933	-100.00%
12	Actuarial (gain) loss	12,024,921	563,657	>300.00%
13	Acquisition	-	-	-
14	Benefits paid	(15,953,629)	(15,958,833)	0.03%
15	Benefit obligation at end of year	$ 363,518,169	$ 339,249,764	7.15%
16	**Change in Plan Assets**	-	-	
17	Fair value of plan assets at beginning of year	$ 213,753,883	$ 287,209,114	-25.58%
18	Actual return on plan assets	65,064,519	(88,636,398)	173.41%
19	Acquisition	-	-	-
20	Employer contribution	80,600,000	31,140,000	158.83%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(15,953,629)	(15,958,833)	0.03%
23	Fair value of plan assets at end of year	$ 343,464,773	$ 213,753,883	60.68%
24	**Funded Status**	$ (20,053,396)	$ (125,495,881)	84.02%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (20,053,396)	$ (125,495,881)	84.02%
30	**Weighted-average Assumptions as of Year End**	-	-	
31	Discount rate	6.00%	6.25%	-4.00%
32	Expected return on plan assets	8.00%	8.00%	
33	Rate of compensation increase	3.50% Union & 3.55% Non-Union	3.50% Union & 3.55% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 7,410,909	$ 7,517,814	-1.42%
36	Interest cost	20,786,204	19,934,599	4.27%
37	Expected return on plan assets	(19,714,992)	(23,940,000)	17.65%
38	Amortization of prior service cost	246,361	246,361	
39	Recognized net actuarial gain	3,787,402	(655,324)	>300.00%
40	Net periodic benefit cost (SEC Basis)	$ 12,515,884	$ 3,103,450	>300.00%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**	-	-	
42	Pension Costs	$ 28,410,000	$ 30,590,000	-7.13%
43	Pension Costs Capitalized	5,392,697	5,928,299	-9.03%
44	Accumulated Pension Asset (Liability) at Year End	$ (20,053,396)	$ (125,495,881)	84.02%
45	**Number of Company Employees:**		-	
46	Covered by the Plan	3,225	3,205	0.62%
47	Not Covered by the Plan			
48	Active	1,095	1,075	1.86%
49	Retired	1,280	1,254	2.07%
50	Deferred Vested Terminated	850	876	-2.97%
	1/ NorthWestern Corporation has a separate pension plan covering South Dakota and Nebraska employees that is not reflected above.			

Sch. 14a	Pension Costs			
1	Plan Name: NorthWestern Energy 401k Retirement Savings Plan			
2	Defined Benefit Plan? No	Defined Contribution Plan? Yes		
3	Actuarial Cost Method? N/A	IRS Code: 401(k)		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? N/A		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			
8	Service cost			
9	Interest cost			
10	Plan participants' contributions	Not Applicable		
11	Amendments			
12	Actuarial loss			
13	Acquisition			
14	Benefits paid			
15	Benefit obligation at end of year	$ -	$ -	
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 146,828,131	$ 207,762,674	41.50%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 5,846,896	$ 5,290,935	10.51%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 192,194,493	$ 146,828,131	30.90%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost			
27	Prepaid (accrued) benefit cost	$ -	$ -	
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate			
31	Expected return on plan assets			
32	Rate of compensation increase			
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			
36	Interest cost			
37	Expected return on plan assets			
38	Amortization of prior service cost			
39	Recognized net actuarial loss			
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 3,851,436	$ 3,334,352	15.51%
44	401(k) Plan Defined Contribution Costs Capitalized	731,067	646,193	13.13%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,343	1,387	-3.17%
48	Not Covered by the Plan			
49	Active - Participating	1,306	1,340	-2.54%
50	Retired			
51	Vested Former Employees, Retirees and Active-	241	285	-15.44%
52	Noncontributing			
	2/ This plan covers all NorthWestern Corporation employees.			
	3/ Represents total company 401(k) plan participants.			

Sch. 15	Other Post Employment Benefits (OPEBS)			
	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: D2007.7.82			
4	Order number: 6852f			
5	Amount recovered through rates	$5,580,735	$2,650,762	110.53%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	5.25%	6.25%	-16.00%
8	Expected return on plan assets	8.00%	8.00%	
9	Medical Cost Inflation Rate 3/	9.25%,4.5%:19	9.5%,4.5%:20	
10	Actuarial Cost Method	Projected Unit Credit Actuarial, Cost Method Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	3.50% Union & 3.55% Non-Union	3.50% Union & 3.55% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	**Describe any Changes to the Benefit Plan:**			
16				

1/ Obtained from NorthWestern Energy-Montana's 2009 FASB 106 Valuation. Assumptions and data are as of December 31, 2009.

2/ Obtained from NorthWestern Energy-Montana's 2008 FASB 106 Valuation. Assumptions and data are as of December 31, 2008.

3/ First Year, Ultimate, Years to Reach Ultimate.

Sch. 15a	Other Post Employment Benefits (OPEBS) (continued)			
	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan			
3	Not Covered by the Plan			
4	Active			
5	Retired			
6	Spouses/Dependants covered by the Plan			
7	**Montana 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$35,998,379	$37,319,466	-3.54%
10	Service cost	992,592	563,273	76.22%
11	Interest Cost	2,774,729	1,981,367	40.04%
12	Plan participants' contributions	-	-	-
13	Amendments	(27,332,377)	-	-
14	Actuarial loss/(gain)	13,336,549	(913,152)	>300.00%
15	Acquisition	-	-	-
16	Benefits paid	(2,907,126)	(2,952,575)	1.54%
17	Benefit obligation at end of year	$22,862,746	$35,998,379	-36.49%
18	**Change in Plan Assets**		-	
19	Fair value of plan assets at beginning of year	$12,420,946	$16,454,260	-24.51%
20	Actual return on plan assets	2,877,298	($5,061,977)	156.84%
21	Acquisition	-		-
22	Employer contribution	2,907,126	$3,981,238	-26.98%
23	Plan participants' contributions	-		-
24	Benefits paid	(2,907,126)	($2,952,575)	1.54%
25	Fair value of plan assets at end of year	$15,298,244	$12,420,946	23.16%
26	**Funded Status**	($7,564,502)	($23,577,433)	67.92%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	($7,564,502)	($23,577,433)	67.92%
31	**Components of Net Periodic Benefit Costs**	-	-	
32	Service cost	$992,592	$563,273	76.22%
33	Interest cost	2,774,729	1,981,367	40.04%
34	Expected return on plan assets	(993,676)	(1,316,341)	24.51%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	-	-	-
37	Recognized net actuarial loss/(gain)	342,380	(568,278)	160.25%
38	Net periodic benefit cost	$3,116,025	$660,021	>300.00%
39	**Accumulated Post Retirement Benefit Obligation**	-	-	
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	2,907,126	$ 2,952,575	-1.54%
43	TOTAL	$2,907,126	$2,952,575	-1.54%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	5,580,735	2,650,762	110.53%
47	TOTAL	$5,580,735	$2,650,762	110.53%
48	**Montana Intrastate Costs:**	-	-	
49	Pension Costs	$5,580,735	$2,650,762	110.53%
50	Pension Costs Capitalized	1,059,318	513,714	106.21%
51	Accumulated Pension Asset (Liability) at Year End	($7,564,502)	($23,577,433)	67.92%
52	**Number of Montana Employees:**		-	
53	Covered by the Plan	2,185	2,159	1.20%
54	Not Covered by the Plan	164	160	2.50%
55	Active	1,112	1,080	2.96%
56	Retired	963	976	-1.33%
57	Spouses/Dependants covered by the Plan	110	103	6.80%

4/ There is approximately an additional $9,490,389 and $8,324,249 in other company OPEBS liabilities outstanding at December 31, 2009 and 2008, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.

SCHEDULE 16

Note: This schedule includes the ten most highly compensated employees assigned or allocated to Montana that are not already included on Sch 17.

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary (Wages)	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year 3/	% Increase Total Compensation
1	Kendall G. Kliewer Vice President, Controller	216,410	67,520 A	37,778 B 23,740 C 63,318 D	408,766	286,273	43%
2	Patrick R. Corcoran Vice President, Government & Regulatory Affairs	189,490	59,121 A	15,719 B 70,965 C 55,424 D 4,014 E	394,733	295,365	34%
3	Bobbi L. Schroeppel Vice President, Customer Care & Communications	203,233	63,409 A	37,929 B 25,010 C 59,456 D 693 F	389,731	292,186	33%
4	Paul J. Evans Former Treasurer	88,440	0 A	28,194 B 9,213 C 216,151 G 4,282 H	346,280	308,674	12%
5	Michael L. Nieman Chief Audit and Compliance Officer	186,531	47,352 A	35,287 B 30,814 C 39,032 D 5,189 E	344,205	242,937	42%
6	Bart A. Thielbar Former Director, Special Projects	26,599	0 A	18,540 B 25,253 C 199,045 G 47,258 H 750 I 55 J	317,500	308,407	3%
7	Gregory Trandem Former Vice President, Administrative Services	29,077	0 A	11,143 B 6,141 C 216,000 G 9,082 H 21,076 J	292,520	349,310	-16%
8	John Fitzpatrick Executive Director State/Local Community Relations	171,430	29,205 A	20,450 B 31,868 C 21,532 D 6,300 I	280,785	N/A	
9	Daniel Rausch Director, Investor Relations & Business Development	168,796	27,706 A	31,871 B 21,857 C 21,198 D	271,429	N/A	
10	Jason Williams Senior Corporate Counsel	127,412	20,251 A	26,411 B 30,000 K 44,285 L	248,360	N/A	

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the 2009 Employee Incentive Compensation Plan. Amounts were earned in 2009 but paid in the first quarter of 2010. Based on company performance against plan, the incentive plan was funded at 108% of target. Individual awards varied from the funded level based on individual performance.

2/ All Other Compensation for named employees consists of the following:

B> Employer contributions to benefits - medical, dental, vision, employee assistance program, group term life, reimbursements of premiums under COBRA, 401(k) match, and non-elective 401(k) contribution.

C>Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2009.

D> Values reflect the grant date fair value for restricted stock awards. Values for 2008 initially reflected the FAS 123R values, *Share-Based Payments*. As a result of the change in SEC rules, the 2009 and 2008 amounts have been reported to reflect the grant date fair value of awards. See footnote 3/.

E> Vacation sold back during the year.

F> Imputed income - personal use of Hebgen Lake property.

G> Lump sum severance payment paid upon termination of employment.

H> Accumulated vacation paid at termination.

I> Vehicle allowance.

J> Final distribution associated with CB SERP bankruptcy settlement.

K> Sign-on bonus.

L> Payments related to relocation.

3/ Total Compensation Reported Last Year amounts for Mr. Kliewer, Ms. Schroeppel, Mr. Evans, Mr. Corcoran, Mr. Nieman, Mr. Thielbar, and Mr. Trandem have been adjusted to reflect a change in SEC valuation of stock compensation. The Total Compensation reported on last year's schedule was: Mr. Kliewer 336,382; Ms. Schroeppel 330,874; Mr. Evans 353,716; Mr. Corcoran 333,546; Mr. Nieman 272,962; Mr. Thielbar 364,207; and Mr. Trandem 423,645. The valuation methodology is consistent between 2008 and 2009.

SCHEDULE 17

Note: This schedule contains the five most highly compensated corporate officers who are assigned or allocated to Montana.

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary (Wages)	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year 3/	% Increase Total Compensation
1	Robert C. Rowe President & Chief Executive Officer	519,231	378,000 A	17,372 B 150,000 C 433,972 D 25,176 E	1,523,751	412,494	269%
2	Brian B. Bird Vice President, Chief Financial Officer & Treasurer	340,624	177,124 A	38,125 B 213,532 D 23,843 E 578 F	793,825	521,547	52%
3	Miggie E. Cramblit Former Vice President, General Counsel, Corporate Secretary & CCO	295,961	123,120 A	33,602 B 123,692 D 19,433 E 2,741 G	598,549	404,582	48%
4	Curtis T. Pohl Vice President, Retail Operations	218,492	79,531 A	41,448 B 73,049 D 55,102 E	467,622	331,972	41%
5	Dave Gates Vice President, Wholesale Operations	224,899	81,863 A	21,332 B 75,179 D 96,633 E 462 F 6,950 H	507,318	372,844	36%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the 2009 Employee Incentive Compensation Plan. Amounts were earned in 2009 but paid in the first quarter of 2010. Based on company performance against plan, the incentive plan was funded at 108% of target.

2/ All Other Compensation for named employees consists of the following:

B> Employer contributions to benefits - medical, dental, vision, employee assistance program, group term life, 401(k) match, and non-elective 401(k) contribution.

C> Imputed income related to the buyout of a contract with Mr. Rowe's former employer.

D> Values reflect the grant date fair value for restricted stock awards. Values for 2008 initially reflected the FAS 123R values, *Share-Based Payments*. As a result of the change in SEC rules, the 2009 and 2008 amounts have been reported to reflect the grant date fair value of awards. See footnote 3/.

E>Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2009.

F> Imputed income - personal use of Hebgen Lake property.

G> Imputed income related to relocation.

H> Vacation sold back during the year.

3/ Total Compensation Reported Last Year amounts for Mr. Bird, Ms. Cramblit, Mr. Gates and Mr. Pohl have been adjusted to reflect a change in SEC valuation of stock compensation. The Total Compensation reported on last year's schedule was: Mr. Bird 653,768; Ms. Cramblit 381,240; Mr. Gates 428,781; and Mr. Pohl 395,812. Mr. Rowe did not receive stock compensation in 2008 so there was no change to his previous amount. The valuation methodology is consistent between 2008 and 2009.

Sch. 18	BALANCE SHEET 1/			
	Account Title	This Year	Last Year	% Change
1	**Assets and Other Debits**			
2	**Utility Plant**			
3	101 Plant in Service	$3,081,332,566	$2,668,916,341	15.45%
4	101.1 Property Under Capital Leases	40,209,537	40,209,537	0.00%
5	105 Plant Held for Future Use	4,900	4,900	0.00%
6	107 Construction Work in Progress	112,452,176	13,392,200	>300.00%
7	108 Accumulated Depreciation Reserve	(1,325,651,718)	(1,301,034,680)	1.89%
8	108.1 Accumulated Depreciation - Capital Leases	(7,036,640)	(5,026,172)	40.00%
9	111 Accumulated Amortization & Depletion Reserves	(36,968,546)	(42,077,470)	-12.14%
10	114 Electric Plant Acquisition Adjustments	-	9,356,285	-100.00%
11	115 Accumulated Amortization-Electric Plant Acq. Adj.	-	(3,011,371)	-100.00%
12	116 Utility Plant Adjustment - Goodwill	355,128,500	355,128,500	0.00%
13	117 Gas Stored Underground-Noncurrent	32,128,064	32,111,698	0.05%
14	**Total Utility Plant**	2,251,598,838	1,767,969,768	27.36%
15	**Other Property and Investments**			
16	121 Nonutility Property	8,301,578	7,935,491	4.61%
17	122 Accumulated Depr. & Amort.-Nonutilility Property	(325,108)	(198,054)	64.15%
18	123.1 Investments in Assoc Companies and Subsidiaries	81,994,051	168,434,709	-51.32%
19	124 Other Investments	475,606	472,249	0.71%
20	128 Miscellaneous Special Funds	-	-	-
21	LT Portion of Derivative Assets - Hedges	-	-	-
22	**Total Other Property & Investments**	90,446,127	176,644,394	-48.80%
23	**Current and Accrued Assets**			
24	131 Cash	1,297,195	11,208,641	-88.43%
25	134 Other Special Deposits	3,072,994	4,027,516	-23.70%
26	135 Working Funds	42,485	42,798	-0.73%
27	136 Temporary Cash Investments	3,000,000	-	-
28	141 Notes Receivable	-	-	-
29	142 Customer Accounts Receivable	62,172,038	69,840,344	-10.98%
30	143 Other Accounts Receivable	17,748,704	13,918,466	27.52%
31	144 Accumulated Provision for Uncollectible Accounts	(2,801,641)	(2,978,917)	-5.95%
32	145 Notes Receivable-Associated Companies	-	-	-
33	146 Accounts Receivable-Associated Companies	10,626,733	7,775,366	36.67%
34	151 Fuel Stock	5,650,758	4,874,590	15.92%
35	154 Plant Materials and Operating Supplies	20,179,708	19,307,628	4.52%
36	164 Gas Stored - Current	21,442,719	46,543,828	-53.93%
37	165 Prepayments	13,651,758	9,723,553	40.40%
38	171 Interest and Dividends Receivable	-	-	-
40	172 Rents Receivable	195,951	139,033	40.94%
41	173 Accrued Utility Revenues	72,260,999	79,144,114	-8.70%
42	174 Miscellaneous Current & Accrued Assets	20,266	3,222,422	-99.37%
43	175 Derivative Instrument Assets (175)	150,885	3,785,419	-96.01%
44	(Less) Long-Term Portion of Derivative Instrument Assets	-	-	-
45	176 LT Portion of Derivative Assets - Hedges	-	-	-
46	(less) LT Portion of Derivative Assets - Hedges	-	-	-
47	**Total Current & Accrued Assets**	228,711,552	270,574,803	-15.47%
48	**Deferred Debits**			
49	181 Unamortized Debt Expense	16,574,042	12,469,833	32.91%
50	182 Regulatory Assets	200,598,280	253,429,595	-20.85%
51	183 Preliminary Survey and Investigation Charges	11,401,286	6,660,776	71.17%
52	184 Clearing Accounts	24,733	32,373	-23.60%
53	185 Temporary Facilities	78	78	0.00%
54	186 Miscellaneous Deferred Debits	259,200	493,054	-47.43%
55	189 Unamortized Loss on Reacquired Debt	8,622,983	5,061,068	70.38%
56	190 Accumulated Deferred Income Taxes	99,750,386	64,595,190	54.42%
57	191 Unrecovered Purchased Gas Costs	(11,500,895)	(22,960,922)	-49.91%
58	**Total Deferred Debits**	325,730,091	319,781,045	1.86%
59	TOTAL ASSETS and OTHER DEBITS	$ 2,896,486,608	$ 2,534,970,010	14.26%

Sch. 18	cont. BALANCE SHEET 1/			
	Account Title	This Year	Last Year	% Change
1	**Liabilities and Other Credits**			
2	**Proprietary Capital**			
3	201 Common Stock Issued	$ 395,396	$ 394,614	0.20%
4	204 Preferred Stock Issued	-	-	-
5	207 Premium on Capital Stock	-	-	-
6	211 Miscellaneous Paid-In Capital	977,847,262	805,900,184	21.34%
7	213 Discount on Capital Stock	-	-	-
8	214 Capital Stock Expense	-	-	-
9	215 Appropriated Retained Earnings	-	-	-
10	216 Unappropriated Retained Earnings	56,921,424	34,370,579	65.61%
12	217 Reacquired Capital Stock	(90,228,082)	(89,487,420)	0.83%
13	219 Accumulated Other Comprehensive Income	9,724,794	12,354,188	-21.28%
14	**Total Proprietary Capital**	954,660,794	763,532,146	25.03%
15	**Long Term Debt**			
16	221 Bonds	905,205,000	600,205,000	50.82%
17	223 Advances in Associated Companies	-	-	-
18	224 Other Long Term Debt	66,000,000	108,000,000	-38.89%
19	226 Unamortized Discount on Long Term Debt-Debit	203,938	56,350	261.91%
20	**Total Long Term Debt**	971,001,062	708,148,650	37.16%
21	**Other Noncurrent Liabilities**			
22	227 Obligations Under Capital Leases-Noncurrent	35,569,936	36,798,159	-3.34%
23	228.1 Accumulated Provision for Property Insurance	-	-	-
24	228.2 Accumulated Provision for Injuries and Damages	15,171,422	10,961,477	38.41%
25	228.3 Accumulated Provision for Pensions and Benefits	21,461,414	71,251,411	-69.88%
26	228.4 Accumulated Miscellaneous Operating Provisions	197,152,803	194,305,799	1.47%
27	229 Accumulated Provision for Rate Refunds	-	1,318	-100.00%
28	230 Asset Retirement Obligations	6,687,525	7,160,145	-6.60%
29	**Total Other Noncurrent Liabilities**	276,043,100	320,478,310	-13.87%
30	**Current and Accrued Liabilities**			
31	231 Notes Payable	-	-	-
32	232 Accounts Payable	100,554,514	102,856,895	-2.24%
33	233 Notes Payable to Associated Companies	-	-	-
34	234 Accounts Payable to Associated Companies	42,544	15,832,169	-99.73%
35	235 Customer Deposits	8,463,347	7,215,417	17.30%
36	236 Taxes Accrued	126,258,987	128,253,825	-1.56%
37	237 Interest Accrued	15,195,595	10,449,036	45.43%
39	238 Dividends Declared	-	-	-
40	241 Tax Collections Payable	1,291,243	2,567,240	-49.70%
41	242 Miscellaneous Current and Accrued Liabilities	37,861,633	56,715,874	-33.24%
42	243 Obligations Under Capital Leases-Current	1,197,088	1,192,887	0.35%
43	244 Derivative Instrument Liabilities	23,812,161	29,155,980	-18.33%
44	245 Derivative Instrument Liabilities - Hedges	-	-	-
45	**Total Current and Accrued Liabilities**	314,677,112	354,239,325	-11.17%
46	**Deferred Credits**			
47	252 Customer Advances for Construction	47,074,278	49,997,718	-5.85%
48	253 Other Deferred Credits	40,096,086	124,713,000	-67.85%
49	254 Regulatory Liabilities	30,489,245	37,383,507	-18.44%
50	255 Accumulated Deferred Investment Tax Credits	2,422,796	2,916,870	-16.94%
51	257 Unamortized Gain on Reacquired Debt	-	-	-
52	281-283 Accumulated Deferred Income Taxes	260,022,135	173,560,485	49.82%
53	**Total Deferred Credits**	380,104,540	388,571,579	-2.18%
54	TOTAL LIABILITIES and OTHER CREDITS	$ 2,896,486,608	$ 2,534,970,010	14.27%

1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana Pipeline Corporation and the Colstrip 4 79 and 143 MW Trusts.

NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 661,000 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and natural gas in Montana since 2002.

The financial statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates. Events occurring subsequent to December 31, 2009, have been evaluated as to their potential impact to the Financial Statements through February 12, 2010, the date the financial statements were available to be issued.

(2) Significant Accounting Policies

Financial Statement Presentation

The financial statements are presented on the basis of the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts. This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Statement of Financial Accounting Standards No. 94 "Consolidation of All Majority-Owned Subsidiaries" (SFAS No. 94). SFAS No. 94 requires that all majority-owned subsidiaries be consolidated (see Note 3). The other significant differences consist of the following:

- Comparative statements of net income per share are not presented;
- Removal costs of transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $209.2 million and $194.3 million as of December 31, 2009 and December 31, 2008, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes;
- Goodwill is reflected in the balance sheets as a utility plant adjustment of $355.1 million as of December 31, 2009 and 2008, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 6);
- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the Balance Sheets as a component of accumulated depreciation of $147.6 million and $192.8 million for December 31, 2009 and December 31, 2008, respectively, in accordance with regulatory treatment as compared to plant for GAAP purposes;
- The current portion of gas stored underground is reflected in the Balance Sheets as current and accrued assets, as compared to materials and supplies for GAAP purposes;
- Current and long-term debt is classified in the Balance Sheets as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt on separate lines; and
- Accumulated deferred tax assets and liabilities are classified in the Balance Sheets as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred tax asset or liability.

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Use of Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, asset retirement obligations, uncollectible accounts, our QF obligation, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we get better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

For our South Dakota and Nebraska operations, as prescribed by the applicable regulatory authorities, electric and natural gas utility revenues are based on billings rendered to customers. For our Montana operations, as prescribed by the Montana Public Service Commission (MPSC), operating revenues are recorded monthly on the basis of consumption or services rendered. Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electrical and natural gas services delivered to customers, but not yet billed at month-end.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

Inventories

Inventories are stated at average cost. Inventory consisted of the following (in thousands):

	December 31,	
	2009	2008
Fuel Stock	$ 5,651	$ 4,875
Materials and supplies	20,180	19,308
Gas stored underground (including the non-current portion reflected in utility plant)	53,571	78,656
	$ 79,402	$ 102,839

Regulation of Utility Operations

Our regulated operations are subject to the provisions of Accounting Standards Codification (ASC) 980, Regulated Operations (ASC 980). Regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

Our Financial Statements reflect the effects of the different rate making principles followed by the jurisdiction regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are expected to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Statement of Income at that time. This would result in a charge to earnings, net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We account for derivative instruments in accordance with ASC 815, Derivatives and Hedging. All derivatives are recognized in the Balance Sheets at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). For fair-value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash-flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Statement of Cash Flows, depending on the underlying nature of the hedged items.

Revenues and expenses on contracts that qualify are designated as normal purchases and normal sales and are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 7, Risk Management and Hedging Activities for further discussion of our derivative activity.

Utility Plant

Utility plant is stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility plant are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of plant is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in utility plant are assets under capital lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to net interest charges, while the equity component is included in other income. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 8.4% and 8.9% for Montana for 2009 and 2008, respectively, and 8.5% and 8.8% for South Dakota for 2009 and 2008, respectively. Interest capitalized totaled \$3.2 million for the year ended December 31, 2009 and \$0.9 million for the year ended December 31, 2008 for Montana and South Dakota combined.

We capitalize preliminary survey and investigation charges related to the determination of the feasibility of transmission or generation utility projects in other deferred debits. Upon commencement of construction, these costs are transferred to construction work in process, and upon completion, these costs will be transferred to utility plant. These costs totaled approximately \$11.4 million and \$6.7 million as of December 31, 2009 and 2008, respectively. Capitalized costs are charged to operating expense if the development of the project is no longer feasible.

We may require contributions in aid of construction from customers when we extend service. Amounts used from these contributions to fund capital additions were \$2.6 million and \$6.9 million for the years ended December 31, 2009 and 2008, respectively.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from three to 40 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 3.2% and 3.3% for 2009 and 2008, respectively.

Depreciation rates include a provision for our share of the estimated costs to decommission three coal-fired generating plants at the end of the useful life of each plant. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in accumulated depreciation.

Income Taxes

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our Statement of Income and provision for income taxes.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if we have prior regulatory authorization for recovery of these costs from customers in future rates. Otherwise, we expense the costs. If an environmental expense is related to facilities we currently use, such as pollution control equipment, then we capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, then we estimate and record only our share of the cost. We treat any future costs of restoring sites where operation may extend indefinitely as a capitalized cost of plant retirement. The depreciation expense levels we can recover in rates include a provision for these estimated removal costs.

Emission Allowances

We have sulfur dioxide (SO2) emission allowances and each allowance permits a generating unit to emit one ton of SO2 during or after a specified year. We have approximately 3,200 excess SO2 emission allowances per year for years 2017 through 2031, however these allowances have no carrying value in our Financial Statements and the market for these years is presently illiquid. These emission allowances are not subject to regulatory jurisdiction. When excess SO2 emission allowances are sold, we reflect the gain in operating income and cash received is reflected as an investing activity.

Accounting Standards Issued

In June 2009, the Financial Accounting Standards Board (FASB) amended the accounting for variable interest entities, which is effective for us beginning January 1, 2010. This revised guidance changes how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar) rights should be consolidated. The determination of whether a company is required to consolidate an entity is based on, among other things, an entity's purpose and design and a company's ability to direct the activities of the entity that most significantly impact the entity's economic performance. The statement includes the following significant provisions:

- requires an entity to qualitatively assess the determination of the primary beneficiary of a variable interest entity (VIE) based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of the primary beneficiary instead of only upon certain triggering events,
- amends the events that trigger a reassessment of whether an entity is a VIE, and
- for an entity that is the primary beneficiary of a VIE, requires separate balance sheet presentation of (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

We are required to consolidate VIEs if we are the primary beneficiary, which means we have a controlling financial interest. Certain long-term purchase power and tolling contracts may be considered variable interests. We have various long-term purchase power contracts with other utilities and certain qualifying facility (QF) plants. We are evaluating our inventory of long-term purchase power and tolling contracts under this guidance. Under the previous guidance, we identified one QF contract that may constitute a VIE. We have accounted for this QF contract as an executory contract as we have been unable to obtain the necessary information from this QF in order to determine if it is a VIE and if so, whether we are the primary beneficiary. Based on the current contract terms with this QF, our estimated gross contractual payments aggregate approximately $468.4 million through 2025. For further discussion of our gross QF liability, see Note 18. During the years ended December 31, 2009 and 2008. purchases from this QF were approximately $20.1 million and $20.5 million, respectively. We will finalize our evaluation during the first quarter of 2010 to determine the impact of adoption, if any, on our financial position and results of operations.

(3) Equity Investments

The following table presents our equity investments reflected in the investments in associated companies on the Balance Sheets (in thousands):

	December 31, 2009	December 31, 2008
Clark Fork & Blackfoot, LLC	$ (7,842)	$ (7,673)
Colstrip 4 79 MW Trust	-	56,355
Colstrip 4 143 MW Trust	-	29,320
Natural Gas Funding Trust	1,643	1,627
NorthWestern Services, LLC	(10,702)	(9,745)
NorthWestern Investments, LLC	95,934	96,028
Risk Partners Assurance, Ltd.	2,961	2,523
Total Investments in Subsidiary Companies	$ 81,994	$ 168,435

(4) Utility Plant

The following table presents the major classifications of our net utility plant (in thousands):

	December 31, 2009	December 31, 2008
Land and improvements	$ 46,819	$ 45,902
Building and improvements	146,439	142,388
Storage, distribution, and transmission	2,180,529	2,114,815
Generation	525,729	182,465
Construction work in process	112,452	13,392
Other equipment	222,031	232,917
	3,233,999	2,731,879
Less accumulated depreciation	(1,369,657)	(1,351,149)
	$ 1,864,342	$ 1,380,730

Plant and equipment under capital lease were $34.0 million and $36.2 million as of December 31, 2009 and December 31, 2008, respectively, which included $33.2 million and $35.2 million as of December 31, 2009 and 2008, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as an obligation under capital lease.

We have an ownership interest in four electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. Our interest in each plant is reflected in the Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Statements of Income. The participants each finance their own investment.

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2009				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 58,021	$ 29,885	$ 44,156	$ 281,279
Accumulated depreciation	38,609	21,729	29,083	46,714
December 31, 2008				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 58,026	$ 29,771	$ 43,406	$ 266,627
Accumulated depreciation	34,636	20,708	26,795	21,462

(5) Asset Retirement Obligations

We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We have identified asset retirement obligations, or ARO, liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time.

Our regulated utility operations have, however, previously recognized removal costs of transmission and distribution assets as a component of depreciation in accordance with regulatory treatment. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. These amounts do not represent legal retirement obligations. As of December 31, 2009 and December 31, 2008, we have recognized accrued removal costs of $209.2 million and $194.3 million, respectively, which are classified as accumulated depreciation. In addition, for our generation properties, we have accrued decommissioning costs since the generating units were first put into service in the amount of $14.9 million and $14.3 million as of December 31, 2009 and December 31, 2008, respectively, which are classified as accumulated depreciation.

The liabilities associated with conditional AROs are adjusted on an ongoing basis due to the passage of new laws and regulations and revisions to either the timing or amount of estimates of undiscounted cash flows and estimates of cost escalation factors. We have recorded a conditional asset retirement obligation of $5.3 million and $6.3 million, as of December 31, 2009 and 2008, respectively, which increases our utility plant and asset retirement obligations. This is primarily related to Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the ARO is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability.

The change in our gross conditional ARO during the year ended December 31, 2009, is as follows (in thousands):

Liability at January 1, 2009	$	7,160
Accretion expense		480
Liabilities incurred		113
Liabilities settled		(1,048)
Revisions to cash flows		(17)
Liability at December 31, 2009	$	6,688

(6) Utility Plant Adjustments

Utility plant adjustments are not amortized; rather, they are evaluated for impairment at least annually. We evaluated our utility plant adjustments during the fourth quarters of 2009 and 2008 and determined that they were not impaired.

(7) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. Commodity price risk is a significant risk due to our lack of ownership of natural gas reserves and minimal ownership of regulated electric generation assets within the Montana market. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices, we routinely enter into derivative contracts, such as fixed-price forward purchase and sales contracts. The objective of these transactions is to fix the price for a portion of anticipated energy purchases to supply our regulated customers. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of seasonal fluctuations in market prices. While we may incur gains or losses on individual contracts, the overall portfolio approach is intended to provide price stability for consumers; therefore, these commodity costs are included in our cost tracking mechanisms. We do not maintain a trading portfolio, and do not currently have any derivative transactions that are not used for risk management purposes. In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. The permitted accounting treatments include: normal purchase normal sale; cash flow hedge; fair value hedge; and mark-to-market. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Normal Purchases and Normal Sales

We have applied the normal purchase and normal sale scope exception (NPNS) to most of our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no amounts recorded in the Financial Statements at December 31, 2009 and 2008. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Mark-to-Market Accounting

Certain contracts for the physical purchase of natural gas associated with our regulated gas utilities do not qualify for NPNS. These are typically forward purchase contracts for natural gas where we lock in a fixed price; however the contracts are settled financially and we do not take physical delivery of the natural gas. We use the mark-to-market method of accounting for these derivative contracts as we do not elect hedge accounting. Upon settlement of these contracts, associated proceeds or costs are refunded to or collected from our customers consistent with regulatory requirements therefore we record a regulatory asset or liability based on changes in market value.

The following table represents the fair value and location of derivative instruments subject to mark-to-market accounting (in thousands). For more information on the determination of fair value see Note 9.

Mark-to-Market Transactions	Balance Sheet Location	December 31, 2009	December 31, 2008
Regulated natural gas net derivative liability	Current Accrued Assets/Liabilities	$ 23,661	$ 29,156

The following table represents the net change in fair value for these derivatives (in thousands):

Derivatives Subject to Regulatory Deferral	Unrealized gain (loss) recognized in Regulatory Assets December 31, 2009	Unrealized gain (loss) recognized in Regulatory Assets December 31, 2008
Natural gas	$ 5,495	$ (23,436)

Credit Risk

We are exposed to credit risk primarily through buying and selling electricity and natural gas to serve customers. Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties.

We enter into commodity master arrangements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: Western Systems Power Pool agreements (WSPP) – standardized power sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements (ISDA) – standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements (NAESB) – standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements – standardized power sales contracts in the electric industry.

Many of our forward purchase contracts contain provisions that require us to maintain an investment grade credit rating from each of the major credit rating agencies. If our credit rating were to fall below investment grade, it would be in violation of these provisions, and the counterparties could require immediate payment or demand immediate and ongoing full overnight collateralization on contracts in net liability positions.

The following table presents, as of December 31, 2009, the aggregate fair value of forward purchase contracts that do not qualify as normal purchases in a net liability position with credit risk-related contingent features, collateral posted, and the aggregate amount of additional collateral that we would be required to post with counterparties, if the credit risk-related contingent features underlying these agreements were triggered on December 31, 2009 (in thousands):

Contracts with Contingent Feature	Fair Value Liability	Posted Collateral	Contingent Collateral
Credit rating	$ 23,199	$ —	$ 23,199

Interest Rate Swaps Designated as Cash Flow Hedges

If we enter into contracts to hedge the variability of cash flows related to forecasted transactions that qualify as cash flow hedges, the changes in the fair value of such derivative instruments are reported in other comprehensive income. The relationship between the hedging instrument and the hedged item must be documented to include the risk management objective and strategy and, at inception and on an ongoing basis, the effectiveness of the hedge in offsetting the changes in the cash flows of the item being hedged. Gains or losses accumulated in other comprehensive income are reclassified to earnings in the periods in which earnings are affected by the variability of the cash flows of the related hedged item. Any ineffective portion of all hedges would be recognized in current-period earnings. Cash flows related to these contracts are classified in the same category as the transaction being hedged.

We have used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. These swaps were designated as cash-flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in Accumulated Other Comprehensive Income (AOCI). We reclassify these gains from AOCI into interest on long-term debt during the periods in which the hedged interest payments occur. The following table shows the effect of these derivative instruments on the Financial Statements:

Cash Flow Hedges	Amount of Gain Remaining in AOCI as of December 31, 2009	Location of Gain Reclassified from AOCI to Income	Amount of Gain Reclassified from AOCI into Income during the Year Ended December 31, 2009
Interest rate contracts	$ 10,464	Interest on long-term debt	$ 1,188

We expect to reclassify approximately $1.2 million of pre-tax gains on these cash-flow hedges from AOCI into interest on long-term debt during the next twelve months. These gains relate to swaps previously terminated, and we have no current interest rate swaps outstanding.

(8) Related Party Transactions

Accounts receivable from and payables to associated companies primarily include intercompany billings for direct charges, overhead, and income tax obligations. The following table reflects our accounts receivable from and accounts payable to associated companies (in thousands):

	December 31, 2009	December 31, 2008
Accounts Receivable from Associated Companies:		
Clark Fork & Blackfoot, LLC	$ 7,190	$ 7,007
NorthWestern Investments, LLC	867	750
NorthWestern Services, LLC	2,552	-
Risk Partners Assurance, Ltd.	18	18
	$ 10,627	$ 7,775
Accounts Payable to Associated Companies:		
Colstrip Unit 4 79 MW Trust	$ -	$ 9,096
Colstrip Unit 4 143 MW Trust	-	6,088
Natural Gas Funding Trust	43	54
NorthWestern Services, LLC	-	594
	$ 43	$ 15,832

(9) Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Measuring fair value requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs.

A fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs has been established by the applicable accounting guidance. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;
- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and
- Level 3 – Significant inputs that are generally not observable from market activity.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. The table below sets forth by level within the fair value hierarchy the gross components of our assets and liabilities measured at fair value on a recurring basis. Normal purchases and sales transactions are not included in the fair values by source table as they are not recorded at fair value. See Note 7 for further discussion.

December 31, 2009	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Temp Cash Investments	$ 3,000	$ —	$ —	$ —	$ 3,000
Other Special Deposits	3,073	—	—	—	3,073
Derivative asset (1)	—	972	—	—	972
Derivative liability (1)	—	(24,633)	—	—	(24,633)
Net derivative position	—	(23,661)	—	—	(23,661)
Total	**$ 6,073**	**$ (23,661)**	**$ —**	**$ —**	**$ (17,588))**
December 31, 2008					
Other Special Deposits	4,028	—	—	—	4,028
Derivative liability (1)	—	(29,156)	—	—	(29,156)
Total	**$ 4,028**	**$ (29,156)**	**$ —**	**$ —**	**$ (25,128)**

(1) The changes in the fair value of these derivatives are deferred as a regulatory asset or liability until the contracts are settled. Upon settlement, associated proceeds or costs are passed through the applicable cost tracking mechanism to customers.

We present our derivative assets and liabilities on a net basis in the Balance Sheets. The table above disaggregates our net derivative assets and liabilities on a gross contract-by-contract basis as required and classifies each individual asset or liability within the appropriate level in the fair value hierarchy, regardless of whether a particular contract is eligible for netting against other contracts. These gross balances are intended solely to provide information on sources of inputs to fair value and do not represent our actual credit exposure or net economic exposure. Increases and decreases in the gross components presented in each of the levels in this table also do not indicate changes in the level of derivative activities. Rather, the primary factors affecting the gross amounts are commodity prices.

Temporary cash investments and other special deposits represent amounts held in money market mutual funds. Fair value for the commodity derivatives was determined using internal models based on quoted forward commodity prices. We consider nonperformance risk in our valuation of derivative instruments by analyzing the credit standing of our counterparties and considering any counterparty credit enhancements (e.g., collateral). The fair value measurement of liabilities also reflects the nonperformance risk of the reporting entity, as applicable. Therefore, we have factored the impact of our credit standing as well as any potential credit enhancements into the fair value measurement of both derivative assets and derivative liabilities. Consideration of our own credit risk did not have a material impact on our fair value measurements.

Financial Instruments

The estimated fair value of financial instruments is summarized as follows (in thousands):

	December 31, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt (including current portion)	$ 971,001	$ 1,016,777	$ 708,149	$ 625,698

The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is necessarily required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

We used the following methods and assumptions to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

- The carrying amounts of temporary cash investments and other special deposits, approximate fair value due to the short maturity of the instruments.
- We determined fair values for debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows.

(10) Long-Term Debt

Long-term debt consisted of the following (in thousands):

	Due	December 31, 2009	December 31, 2008
Unsecured Debt:			
Unsecured Revolving Line of Credit	2012	$ 66,000	$ 108,000
Secured Debt:			
Mortgage bonds—			
South Dakota—6.05%	2018	55,000	55,000
Montana—6.04%	2016	150,000	150,000
Montana—6.34%	2019	250,000	—
Montana—5.71%	2039	55,000	—
South Dakota & Montana—5.875%	2014	225,000	225,000
Pollution control obligations—			
Montana—4.65%	2023	170,205	170,205
Discount on Notes and Bonds	—	(204)	(56)
		$ 971,001	$ 708,149

Unsecured Revolving Line of Credit

On June 30, 2009, we amended and restated our unsecured revolving line of credit scheduled to expire on November 1, 2009. The amended facility extends the term to June 30, 2012, and increases the aggregate principal amount available under the facility by $50 million to $250 million. The amended facility does not amortize and borrowings will bear interest based on a credit ratings grid. A total of nine banks participate in the new facility, with no one bank providing more than 14% of the total availability. The amended facility contains covenants substantially similar to the previous facility.

The 'spread' or 'margin' ranges from 2.25% to 4.0% over the London Interbank Offered Rate (LIBOR). The facility bears interest at a rate of approximately 3.23%, which is 3.0% over LIBOR, as of December 31, 2009, and we had $3.1 million in letters of credit and $66 million of borrowings outstanding. The weighted average interest rate on the outstanding revolving credit facility borrowings was 2.9% as of December 31, 2009.

Commitment fees for the unsecured revolving line of credit were $0.7 million and $0.3 million for the years ended December 31, 2009 and 2008, respectively.

The credit facility includes covenants, which require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65%. The amended and restated line of credit also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the credit facility; however a default on the credit facility would not trigger a default on any other obligations.

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. All of such bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds and Montana Pollution Control Obligations are secured by substantially all of our Montana electric and natural gas assets.

Financing Transactions

In March 2009, we issued $250 million of Montana First Mortgage Bonds at a fixed interest rate of 6.34% maturing April 1, 2019, which were discounted to yield 6.349%. The bonds are secured by our Montana electric and natural gas assets. The bonds were issued in a transaction exempt from registration under the Securities Act of 1933, as amended. We completed an offer to exchange these bonds for a like series of bonds registered under the Securities Act of 1933 during the third quarter of 2009. We used the proceeds to redeem our $100 million Colstrip Lease Holdings LLC term loan, repay outstanding borrowings on our revolving credit facility, repay other outstanding debt obligations of $31.7 million related to Colstrip Unit 4, fund a portion of the costs of the Mill Creek generation project, and fund future capital expenditures.

On October 15, 2009 we issued $55 million of Montana First Mortgage Bonds at a fixed interest rate of 5.71% maturing October 15, 2039. The bonds are secured by our Montana electric and natural gas assets. The transaction is exempt from the registration requirements of the Securities Act of 1933, as amended. We used the proceeds to fund a portion of the costs of the Mill Creek generation project and capital expenditures.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt during the next five years are zero in 2010 and 2011, $66.0 million in 2012, zero in 2013 and $225.0 million in 2014.

As of December 31, 2009, we are in compliance with our financial debt covenants.

(11) Income Taxes

In December 2008, we filed a request with the Internal Revenue Service (IRS) to change our tax accounting method related to costs to repair and maintain utility assets. The IRS approved our request in September 2009, which allowed us to take a current tax deduction for a significant amount of repair costs that were previously capitalized for tax purposes.

These repair costs are capitalized and depreciated for book purposes. We record a deferred income tax liability as we flow the temporary timing differences between book and tax treatment through to our customers in the form of lower rates. A regulatory asset is established to reflect that future increases in taxes payable will be recovered from customers as the temporary differences reverse. Due to this regulatory treatment, we recorded an income tax benefit of approximately $16.6 million during the year ended December 31, 2009 to reflect this change in tax accounting method, of which approximately $8.7 million and $7.9 million related to the 2009 and 2008 tax years, respectively. For years prior to 2008, we have not recorded a regulatory asset for the repairs deduction pending regulatory review. This change in tax accounting method will have the effect of increasing and extending our net operating loss carryforwards.

Deferred income taxes relate primarily to the difference between book and tax methods of depreciating property, amortizing tax-deductible goodwill, the difference in the recognition of revenues and expenses for book and tax purposes, certain natural gas and electric costs which are deferred for book purposes but expensed currently for tax purposes, and net operating loss carry forwards.

The components of the net deferred income tax liability recognized in our Balance Sheets are related to the following temporary differences (in thousands):

	December 31, 2009	December 31, 2008
Excess tax depreciation	$ (189,714)	$ (133,462)
Regulatory assets	(4,479)	(14,144)
Regulatory liabilities	709	707
Unbilled revenue	3,058	2,289
Unamortized investment tax credit	1,305	1,571
Compensation accruals	2,040	5,258
Reserves and accruals	(19,245)	22,967
Utility plant adjustments amortization	(68,434)	(59,674)
Net operating loss (NOL) carryforward	111,439	62,917
AMT credit carryforward	5,604	5,862
Valuation allowance	(3,264)	(3,331)
Other, net	709	75
	$ (160,272)	$ (108,965)

A valuation allowance is recorded when a company believes that it will not generate sufficient taxable income of the appropriate character to realize the value of its deferred tax assets. We have a valuation allowance against certain state NOL carryforwards as we do not believe these assets will be realized.

At December 31, 2009 we estimate our total federal NOL carryforward to be approximately $475.9 million. If unused, our federal NOL carryforwards will expire as follows: $171.0 million in 2023; $192.1 million in 2025; $88.1 million in 2028; and $24.7 million 2029. We estimate our state NOL carryforward as of December 31, 2009 is approximately $595.8 million. If unused, our state NOL carryforwards will expire as follows: $318.9 million in 2010; $33.8 million in 2011; $152.9 million in 2012; $70.5 million in 2015; and $19.7 million in 2016. Management believes it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards except as noted above.

We have elected under Internal Revenue Code 46(f)(2) to defer investment tax credit benefits and amortize them against expense and customer billing rates over the book life of the underlying plant.

Uncertain Tax Positions

We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The change in unrecognized tax benefits is as follows (in thousands):

	2009	2008
Unrecognized Tax Benefits at January 1	$ 115,105	$ 111,124
Gross increases - tax positions in prior period	9,960	6,468
Gross decreases - tax positions in prior period	(2,221)	(2,487)
Unrecognized Tax Benefits at December 31	$ 122,844	$ 115,105

Our unrecognized tax benefits include approximately $85.1 million related to tax positions as of December 31, 2009 and 2008, respectively that if recognized, would impact our annual effective tax rate. We do not anticipate total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitations within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. During the years ended December 31, 2009 and 2008, we have not recognized expense for interest or penalties, and do not have any amounts accrued at December 31, 2009 and 2008, respectively, for the payment of interest and penalties.

Our federal tax returns from 2000 forward remain subject to examination by the Internal Revenue Service.

(12) Accumulated Other Comprehensive Income

The following table displays the components of AOCI, which is included in proprietary capital on the Balance Sheets (in thousands).

	Net Unrealized Gains on Hedging Instruments	Pension and Other Benefits	Other	Total
Balances December 31, 2007	$ 12,841	$ 509	$ 398	$ 13,748
Reclassification of net gains on hedging instruments from OCI to net income	(1,188)	—	—	(1,188)
Pension and postretirement medical liability adjustment, net of tax of $128	—	204	—	204
Foreign currency translation	—	—	(410)	(410)
Balances December 31, 2008	11,653	713	(12)	12,354
Reclassification of net gains on hedging instruments from OCI to net income	(1,188)	—	—	(1,188)
Pension and postretirement medical liability adjustment, net of tax of $1,088	—	(1,737)	—	(1,737)
Foreign currency translation	—	—	296	296
Balance at December 31, 2009	$ 10,465	$ (1,024)	$ 284	$ 9,725

(13) Operating Leases

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2009 future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2010	$ 1,529
2011	1,079
2012	688
2013	86
2014	63

Lease and rental expense incurred was $1.8 million and $2.1 million for the years ended December 31, 2009 and 2008, respectively.

(14) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees, which includes two cash balance pension plans. The plan for our South Dakota and Nebraska employees is referred to as the NorthWestern pension plan, and the plan for our Montana employees is referred to as the NorthWestern Energy pension plan.

We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plan's funded status is recognized as an asset or liability in our financial statements. See Note 16 for further discussion on how these costs are recovered through rates charged to our customers.

Plan Amendment

In 2009, we amended our postretirement medical plan to: (i) cap the company contribution toward the premium cost for coverage; (ii) provide a company contribution toward the premium cost for coverage to our South Dakota and Nebraska retirees; and (iii) change eligibility provisions for the company contributions from age 50 with 5 years of service to age 60 with 20 years of service for employees terminating on or after January 1, 2011. Previously, only our Montana retirees received a company contribution.

In 2008, we amended our NorthWestern Corporation and NorthWestern Energy pension plans to close the plans to new employees effective January 1, 2009. New employees are eligible to participate in the defined contribution plan.

Benefit Obligation and Funded Status

Following is a reconciliation of the changes in plan benefit obligations and fair value and a statement of the funded status (in thousands):

	Pension Benefits December 31, 2009	Pension Benefits December 31, 2008	Other Postretirement Benefits December 31, 2009	Other Postretirement Benefits December 31, 2008
Change in Benefit Obligation:				
Obligation at beginning of period	$ 388,659	$ 376,872	$ 44,323	$ 46,494
Service cost	8,270	8,405	993	563
Interest cost	23,705	22,875	3,149	2,367
Plan amendments	—	49	(25,427)	—
Actuarial loss (gain)	13,962	405	14,191	(1,275)
Gross benefits paid	(19,318)	(19,947)	(4,882)	(3,826)
Benefit obligation at end of period	$ 415,278	$ 388,659	$ 32,347	$ 44,323
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 242,228	$ 330,446	$ 12,421	$ 16,455
Return on plan assets	75,619	(101,005)	2,877	(5,063)
Employer contributions	92,900	32,734	4,882	4,855
Gross benefits paid	(19,318)	(19,947)	(4,882)	(3,826)
Fair value of plan assets at end of period	$ 391,429	$ 242,228	$ 15,298	$ 12,421
Funded Status	$ (23,849)	$ (146,431)	$ (17,049)	$ (31,902)
Unrecognized net actuarial (gain) loss	—	—	—	—
Unrecognized prior service cost	—	—	—	—
Accrued benefit cost	$ (23,849)	$ (146,431)	$ (17,049)	$ (31,902)
Amounts recognized in the balance sheet consist of:				
Current liability	—	—	(1,028)	(883)
Noncurrent liability	(23,849)	(146,431)	(16,021)	(31,019)
Net amount recognized	$ (23,849)	$ (146,431)	$ (17,049)	$ (31,902)
Amounts recognized in regulatory assets consist of:				
Transition obligation	—	—	—	—
Prior service (cost) credit	(1,734)	(1,980)	27,332	—
Net actuarial (loss) gain	(38,711)	(82,061)	(9,908)	1,203
Amounts recognized in AOCI consist of:				
Transition obligation	—	—	—	—
Prior service cost	—	—	(1,905)	—
Net actuarial gain	—	—	21	941
Total	$ (40,445)	$ (84,041)	$ 15,540	$ 2,144

The total projected benefit obligation and fair value of plan assets for the pension plans with projected benefit obligations in excess of plan assets were as follows (in millions):

	Pension Benefits	
	December 31,	
	2009	2008
Projected benefit obligation	$ 415.3	$ 388.7
Accumulated benefit obligation	413.2	386.5
Fair value of plan assets	391.4	242.2

Net Periodic Cost

The components of the net costs for our pension and other postretirement plans are as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2009	2008	2007	2009	2008	2007
Components of Net Periodic Benefit Cost						
Service cost	$ 8,270	$ 8,405	$ 8,947	$ 993	$ 563	$ 580
Interest cost	23,705	22,875	21,800	3,149	2,367	2,442
Expected return on plan assets	(22,383)	(27,212)	(24,422)	(994)	(1,316)	(1,068)
Amortization of transitional obligation	—	—	—	—	—	—
Amortization of prior service cost	246	246	242	—	—	—
Recognized actuarial loss (gain)	4,058	(818)	—	277	(599)	(259)
Net Periodic Benefit Cost	$ 13,896	$ 3,496	$ 6,567	$ 3,425	$ 1,015	$ 1,695

We estimate amortizations from regulatory assets into net periodic benefit cost during 2010 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service cost	$ 246	$ (1,952)
Accumulated gain	—	586

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2009 and 2008. The actuarial assumptions used to compute the net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these items generally have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

For 2009 and 2008, we set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. During the fourth quarter of 2009, we revised our target asset allocation from 70% equity securities, and 30% fixed-income securities to 60% equity securities, and 40% fixed-income securities. Considering this information and future expectations for asset returns, we reduced our expected long-term rate of return on assets assumption from 8.00% to 7.75% for 2010.

The health care cost trend rates are established through a review of actual recent cost trends and projected future trends. Our retiree medical trend assumptions are the best estimate of expected inflationary increases to our healthcare costs. Due to the relative size of our retiree population (under 800 members), the assumptions used are based upon both nationally expected trends and our specific expected trends. Our average increase remains consistent with the nationally expected trends.

The weighted-average assumptions used in calculating the preceding information are as follows:

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2009	2008	2007	2009	2008	2007
Discount rate	5.75-6.00%	6.25%	6.25%	4.75-6.00%	6.00-6.25%	5.75-6.00%
Expected rate of return on assets	8.00	8.00	8.00	8.00	8.00	8.00
Long-term rate of increase in compensation levels (nonunion)	3.58	3.58	3.58	3.58	3.55	3.55
Long-term rate of increase in compensation levels (union)	3.50	3.50	3.50	3.50	3.50	3.50

The postretirement benefit obligation is calculated assuming that health care costs increased by 9.5% in 2009 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually to 4.5% by the year 2029.

Assumed health care cost trend rates have had a significant effect on the amounts reported for the costs each year as well as on the accumulated postretirement benefit obligation. With our 2009 plan amendment to cap the company contribution toward the premium cost, future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation. The following table sets forth the sensitivity of retiree welfare results (in thousands):

Effect of a one percentage point increase in assumed health care cost trend		
On total service and interest cost components	$	—
On postretirement benefit obligation		—
Effect of a one percentage point decrease in assumed health care cost trend		
On total service and interest cost components	$	(1)
On postretirement benefit obligation		(14)

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, and the Prudent Man Rule of the Employee Retirement Income Security Act of 1974. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each Plan should be substantially fully invested as long-term cash holdings reduce long-term rates of return;
- It is prudent to diversify each Plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the Plans should strongly correlate with the interest rate sensitivity of the Plan's aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the overall funded status;
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;

- A portion of plan assets should be allocated to passive, indexed management to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense. In the optimization study, assumptions are formulated about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Based on this, the target asset allocation established, within an allowable range of plus or minus 5%, is as follows:

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2009	2008	2009	2008
Debt securities	40.0%	30.0%	40.0%	30.0%
Domestic equity securities	50.0	60.0	50.0	60.0
International equity securities	10.0	10.0	10.0	10.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2009	2008	2009	2008	2009	2008
Cash and cash equivalents	—%	0.1%	—%	—%	—%	—%
Debt securities	38.9	31.2	39.1	34.3	36.9	31.2
Domestic equity securities	51.2	58.6	51.0	56.6	52.5	58.8
International equity securities	9.9	10.1	9.9	9.1	10.6	10.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. Debt securities consist of U.S. as well as international instruments. Core domestic portfolios can be invested in government, corporate, asset-backed and mortgage-backed obligation securities. The portfolio may invest in high yield securities, however, the average quality must be rated at least "investment grade" by rating agencies. Performance of fixed income investments shall be measured by both traditional investment benchmarks as well as relative changes in the present value of the plans liabilities. Equity investments consist primarily of U.S. stocks including large, mid and small cap stocks, which are diversified across investment styles such as growth and value. Non-U.S. equities are utilized with exposure to developing and emerging markets. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes.

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the SEC. Investments in a collective investment vehicle are valued by multiplying the investee company's net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT's investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT's investment manager if applicable. The direct holding of NorthWestern Corporation stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. In addition, the NorthWestern Corporation pension plan assets also include a participating group annuity contract in the John Hancock General Investment Account, which consists primarily of fixed-income securities. The participating group annuity contract is valued based on discounted cash flows of current yields of similar contracts with comparable duration based on the underlying fixed income investments.

The fair value of our plan assets at December 31, 2009 by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 45	$ —	$ 45	$ —
Equity securities: (1)				
US small/mid cap growth	17,533	—	17,533	—
US small/mid cap value	17,414	—	17,414	—
US large cap growth	53,835	—	53,835	—
US large cap value	52,561	—	52,561	—
US large cap passive	58,937	—	58,937	—
Non-US core	38,709	—	38,709	—
Fixed income securities:(2)				
US core opportunistic	29,240	—	29,240	—
US passive	16,419	—	16,419	—
Long duration	92,325	—	92,325	—
Ultra long duration	3,278	—	3,278	—
Participating group annuity contract	11,133	—	11,133	—
	$ 391,429	$ —	$ 391,429	$ —
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 4	$ —	$ 4	$ —
Equity securities: (1)				
US small/mid cap growth	837	715	122	—
US small/mid cap value	810	689	121	—
S&P 500 index	5,238	—	5,238	—
US large cap growth	375	—	375	—
US large cap value	367	—	367	—
US large cap passive	410	—	410	—
Non-US core	1,623	1,354	269	—
Fixed income securities: (2)				
Passive bond market	1,008	—	1,008	—
US core opportunistic	3,786	3,565	221	—
US passive	120	—	120	—
Long duration	694	—	694	—
Ultra long duration	26	—	26	—
	$ 15,298	$ 6,323	$ 8,975	$ —

(1) This category consists of active and passive managed equity funds, which are invested in multiple strategies to diversify risks and reduce volatility.
(2) This category consists of investment grade bonds of U.S. issuers from diverse industries, debt securities issued by national, state and local governments, and asset-backed securities. This includes both active and passive managed funds.

For further discussion of the three levels of the fair value hierarchy see Note 9.

Cash Flows

Due to the unprecedented volatility in equity markets, we experienced plan asset market gains during 2009 in excess of 20%, and plan asset market losses during 2008 in excess of 30%, which impact our planned levels of contributions. In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. On March 31, 2009, the U.S. Department of the Treasury (Treasury) provided guidance on the selection of the corporate bond yield curve for determining plan liabilities and allowed companies to choose from the range of months in selecting a rate, rather than requiring the use of prescribed rates. The Treasury's announcement specifically referenced 2009, but also indicated that technical guidance will be forthcoming to address future years. In addition, the IRS and Treasury issued final regulations effective October 15, 2009 applying to plan years beginning on or after January 1, 2010 which provided guidance on pension plan funding requirements.

Based on the assumptions allowed under the PPA, WRERA, Treasury guidance and IRS guidance, and the significant contributions made during 2009, we estimate minimum required contributions in the future will be approximately $9 million. We may elect to make contributions earlier than the required dates. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact these funding requirements.

Due to the regulatory treatment of pension costs in Montana, expense is calculated using the average of our actual and estimated funding amounts from 2005 through 2012, therefore changes in our funding estimates creates increased volatility to earnings. As a result of the significant increase in unfunded status as of December 31, 2008, we reviewed our funding strategy for the plans, and significantly increased our 2009 cash funding in order to decrease the volatility of these plans to our long-term results of operations and liquidity as follows:

	2009	2008	2007
NorthWestern Energy Pension Plan (MT)	$ 80,600	$ 31,140	$ 21,966
NorthWestern Pension Plan (SD)	12,300	1,594	672
	$ 92,900	$ 32,734	$ 22,638

The 2009 contributions exceeded our minimum funding requirements by approximately $75.0 million. For our postretirement medical benefits, our policy is to contribute an amount equal to the annual actuarially determined cost that is also recoverable in rates. We generally fund our postretirement medical trusts monthly, subject to our liquidity needs and the maximum deductible amounts allowed for income tax purposes.

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2010	$ 22,047	$ 3,818
2011	23,327	3,558
2012	23,900	3,331
2013	25,714	3,331
2014	26,740	3,295
2015-2019	155,834	14,801

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the year ended December 31, 2009 and 2008 were $5.8 million and $5.3 million, respectively.

(15) Stock-Based Compensation

We grant stock-based awards through our 2005 Long-Term Incentive Plan (LTIP), which includes service based restricted stock awards and performance share awards. As of December 31, 2009, there were 521,828 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to three years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

Restricted Stock and Performance Share Awards

Restricted stock awards vest within five years after the date of grant. The fair value of restricted stock is measured based upon the closing market price of our common stock as of the date of grant. Performance share awards are typically payable at the end of a three-year performance period if the specified performance criteria are met.

Performance share awards were granted under the 2005 LTIP during 2009. With these awards, shares will vest if, at the end of the three-year performance period, we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. These awards contain both a market and performance based component. The performance goals for these awards are independent of each other and equally weighted, and are based on two metrics: (i) cumulative earnings per share (EPS) and return on equity growth; and (ii) total shareholder return (TSR) relative to a peer group. The fair value of the EPS component is estimated based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple determined on the basis of historical experience, which is subsequently trued up at vesting based on actual performance. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The significant assumptions used to calculate fair value of the TSR component also included a three-year risk-free rate of 1.37%, volatility of 25.1% to 46.5% for the peer group, and maintenance of our $1.34 annual dividend over the performance period. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of nonvested shares as of December 31, 2009, and changes during the year ended December 31, 2009 are as follows:

	Performance Share Awards		Restricted Stock Awards	
	Shares	**Weighted-Average Grant-Date Fair Value**	**Shares**	**Weighted-Average Grant-Date Fair Value**
Beginning nonvested grants	—	$ —	194,072	$ 34.39
Granted	80,515	21.53	8,000	22.85
Vested	—	—	(117,905)	33.75
Forfeited	(2,169)	21.53	(14,213)	34.60
Remaining nonvested grants	78,346	$ 21.53	69,954	$ 34.37

We recognized compensation expense of $1.8 million and $3.2 million for the years ended December 31, 2009 and 2008, respectively, and a related income tax (expense) benefit of $(0.6) million and $0.2 million for the years ended December 31, 2009 and 2008, respectively. As of December 31, 2009, we had $1.7 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected in other paid-in capital in our Balance Sheets. The cost is expected to be recognized over a weighted-average period of 1.1 years. The total fair value of shares vested was $4.0 million and $4.7 million for the years ended December 31, 2009 and 2008, respectively.

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director's compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years). During the years ended December 31, 2009, 2008 and 2007, DSUs issued to members of our Board totaled 42,870, 33,750 and 30,563, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2009 and 2008 was approximately $1.1 million and $0.2 million, respectively.

(16) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of ASC 980, as discussed in Note 2. Pursuant to this pronouncement, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to the customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following table reflects our major classifications of regulatory assets and liabilities (in thousands of dollars) that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. Of these regulatory assets and liabilities, energy supply costs are the only items earning a rate of return. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods. Because these costs are recovered as paid, they do not earn a return. We have specific orders to cover approximately 97% of our regulatory assets and 100% of our regulatory liabilities.

	Note Reference	Remaining Amortization Period	December 31, 2009	December 31, 2008
Pension	14	Undetermined	$ 87,934	$ 148,534
Postretirement benefits	14	Undetermined	6,191	25,010
Environmental clean-up		Various	14,631	15,904
Energy supply derivatives	7	1 Year	23,812	29,156
Income taxes	11	Plant Lives	47,241	16,466
Other		Various	20,789	18,360
Total regulatory assets			**$ 200,598**	**$ 253,430**
Gas storage sales		30 Years	$ 12,513	$ 12,933
Supply costs		1 Year	6,355	5,465
Energy supply derivatives		1 Year	2,044	3,785
Environmental clean-up		1 Year	1,041	1,411
State & local taxes & fees		1 Year	6,012	9,701
Other		Various	2,524	4,089
Total regulatory liabilities			**$ 30,489**	**$ 37,384**

Pension and Postretirement Benefits

We recognize the unfunded portion of plan benefit obligations in the Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The South Dakota Public Utilities Commission (SDPUC) allows recovery of pension costs on an accrual basis. The MPSC allows recovery of postretirement benefit costs on an accrual basis. The volatility in plan asset market returns and significant increases in funding is discussed in Note 14, and is reflected in regulatory assets above.

Environmental clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 18. Our 2007 natural gas rate case settlement with the SDPUC allows recovery of manufactured gas plant (MGP) environmental clean-up costs, which is reflected as a regulatory asset above.

Income Taxes

Tax assets primarily reflect the effects of plant related temporary differences such as removal costs, capitalized interest and contributions in aid of construction that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse.

Deferred Financing Costs

Consistent with our historical regulatory treatment, a regulatory asset has been established to reflect the remaining deferred financing costs on long-term debt that has been replaced through the issuance of new debt. These amounts are amortized over the life of the new debt.

State & Local Taxes & Fees (Montana Property Tax Tracker)

Under Montana law, we are allowed to track the increases in the actual level of state and local taxes and fees and recover these amounts. The MPSC has authorized recovery of approximately 60% of the estimated increase in our local taxes and fees (primarily property taxes) as compared to the related amount included in rates during our last general rate case.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

(17) Regulatory Matters

Montana General Rate Case

In October 2009, we filed a request with the Montana Public Service Commission (MPSC) for an annual electric transmission and distribution revenue increase of $15.5 million, and an annual natural gas transmission, storage and distribution revenue increase of $2.0 million. The request was based on a 2008 test period, a return on equity of 10.9%, an equity ratio of 49.45% and rate base of $632.2 million and $256.6 million for electric and natural gas, respectively.

The procedural schedule for this rate case was temporarily suspended pending resolution of confidential treatment of various data requests, which was resolved in April 2010. We expect the procedural schedule to be reinstated during the second quarter of 2010 and the MPSC to issue a final order during the fourth quarter of 2010. We requested interim rate adjustments, which we expect to be considered after intervener testimony is filed. Final rate adjustments would become effective upon the issuance of a final order on this matter.

Montana Electric and Natural Gas Supply Trackers

Rates for our Montana electric and natural gas supply are set by the MPSC. Each year we submit electric and natural gas tracker filings for recovery of supply costs for the 12-month period ended June 30 and for the projected electric supply costs for the next 12-month period. The MPSC reviews such filings and makes its cost recovery determination based on whether or not our electric and natural gas energy supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, then it may disallow such costs.

Our annual electric supply cost tracker requests for the 12-month periods ended June 30, 2008 and June 30, 2009 were combined and are still pending final approval of the MPSC. During the fourth quarter of 2009, we entered into a settlement with the Montana Consumer Counsel agreeing to remove approximately $183,000 in labor costs and calculated lost revenues from the tracker. The MPSC conducted a hearing to review the filings and resulting settlement and briefing was completed in March 2010. We expect the MPSC to issue an order during the second quarter of 2010.

On June 2, 2009, we filed an annual gas cost tracker request with the MPSC for any unrecovered actual gas costs for the 12-month period ended June 30, 2009, and for the projected gas costs for the 12-month period ending June 30, 2010. On June 24, 2009, the MPSC issued an interim order, approving recovery of our projected gas costs pending its review. A procedural schedule has been established.

Montana Property Tax Tracker

In December 2009, we filed our annual property tax tracker (including other state/local taxes and fees) with the MPSC for an automatic rate adjustment, which reflected 60% of the change in 2009 actual property taxes and estimated property taxes for 2010. This filing also included an adjustment for property taxes related to Colstrip Unit 4 (Colstrip). In our 2008 filing requesting to include our interest in Colstrip in utility rate base, we estimated base property taxes would be approximately $5.5 million, by multiplying the rate base value by the latest known mill levy. This filing was approved by the MPSC. Actual 2009 Colstrip related property taxes were approximately $2.1 million and we proposed refunding 60% of the change to customers, consistent with previous MPSC orders. In January 2010, the MPSC issued an order requiring us to reset the base rates for Colstrip, effectively requiring us to refund 100% of the change in property taxes from our original 2008 filing. We disputed various aspects of the order and filed a Motion for Reconsideration with the MPSC. In March 2010, the MPSC issued an order on reconsideration to remove or clarify language from their initial order, but did not change the decision on recovery of property taxes.

Mill Creek Generating Station

In August 2008, we filed a request with the MPSC for advanced approval to construct a 150 megawatt (MW) natural gas fired facility. The Mill Creek Generating Station, estimated to cost approximately $202 million, will provide regulating resources to balance our transmission system in Montana to maintain reliability and enable wind power to be integrated onto the network to meet renewable energy portfolio needs. In May 2009, the MPSC issued an order granting approval to construct the facility, authorizing a return on equity of 10.25% and a preliminary cost of debt of 6.5%, with a capital structure of 50% equity and 50% debt. In addition, the MPSC determined the $81 million cost for the turbines is prudent, with the remainder of the project costs to be submitted to the MPSC for review and approval once construction of the facility is complete. Construction began in June 2009, and the plant is scheduled to be operational by December 31, 2010. As of March 31, 2010, we have capitalized approximately $119.8 million in construction work in process related to this project.

Our Federal Energy Regulatory Commission (FERC) Open Access Transmission Tariff (OATT) allows for pass-through of ancillary costs to our customers, including the regulating reserve service described above to be provided by the Mill Creek Generating Station under Schedule 3 (Regulation and Frequency Response). We anticipate making the appropriate FERC filings related to this project in the second quarter of 2010 in order to reflect the cost of service for the Mill Creek Generating Station under the OATT in Schedule 3.

Transmission Investment Projects

We are conducting open season processes for the proposed Mountain States Transmission Intertie and Collector Project to identify potential interest for new transmission capacity on these paths due to the changing nature of generation projects. The open seasons were initiated with an informational meeting for prospective bidders in March 2010. The open season process is designed to provide for a staged level of commitment by prospective users. Assuming sufficient interest, we would expect to make filings with FERC early in 2011. We have capitalized approximately $12.3 million of preliminary survey and investigative costs associated with these proposed transmission projects. We discuss these transmission investment opportunities further in the "Overview" section of Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2009.

Reliability Compliance

We completed our compliance audit for our Montana operations under the compliance monitoring and enforcement program of the WECC, a regional electric reliability organization, during 2009. WECC has responsibility for monitoring and enforcing compliance with the FERC approved mandatory reliability standards within the western interconnection of the Unites States. In connection with the compliance audit, WECC found no violations of the applicable standards. Since June 2007, we have identified and self-reported violations of 32 requirements to WECC. All but nine of these violations were dismissed or were subject to expedited dispositions with no penalties. During the fourth quarter of 2009, we reached a settlement agreement with WECC addressing six of the remaining nine violations for a total penalty of $80,000, which has been accrued. The settlement is pending formal North American Electric Reliability Corporation (NERC) and FERC approval. The remaining three violations all relate to one standard and this standard is pending a NERC interpretation. We also filed mitigation plans for two potential violations with the Midwest Reliability Organization (MRO) for our South Dakota operations. We have completed the mitigation measures in compliance with the plans and expect resolution with MRO during the second quarter of 2010 without material impact. We expect our compliance with NERC standards will be audited at least every three years.

(18) Commitments and Contingencies

Qualifying Facilities Liability

In Montana we have certain contracts with Qualifying Facilities, or QFs. The QFs require us to purchase minimum amounts of energy at prices ranging from $65 to $167 per MWH through 2029. Our estimated gross contractual obligation related to the QFs is approximately $1.4 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $1.1 billion through 2029. The fair value of the remaining QF liability is recorded in our Balance Sheets. The following summarizes the change in the QF liability (in thousands):

	December 31,	
	2009	2008
Beginning QF liability	$ 162,841	$ 158,132
Unrecovered amount	(9,366)	(7,246)
Interest expense	12,364	11,955
Ending QF liability	$ 165,839	$ 162,841

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross Obligation	Recoverable Amounts	Net
2010	$ 63,589	$ 53,835	$ 9,754
2011	65,323	54,357	10,966
2012	67,111	54,904	12,207
2013	69,816	55,462	14,354
2014	72,354	56,025	16,329
Thereafter	1,059,402	797,190	262,212
Total	$ 1,397,595	$ 1,071,773	$ 325,822

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 20 years. Costs incurred under these contracts were approximately $433.7 million and $563.0 million and $445.0 million for the years ended December 31, 2009 and 2008, and 2007, respectively. As of December 31, 2009 our commitments under these contracts are $362.1 million in 2010, $191.0 million in 2011, $173.6 million in 2012, $161.2 million in 2013, $120.3 million in 2014, and $659.4 million thereafter. These commitments are not reflected in our Financial Statements.

Other Purchase Obligations

We have entered into purchase obligations related to the construction of the Mill Creek Generating Station, which primarily include engineering, procurement and construction (EPC) and gas turbine generators. Total payments under these contracts were $67.9 million during 2009. Our estimated future obligation under these contracts is $70.8 million for 2010.

ENVIRONMENTAL LIABILITIES

The operation of electric generating, transmission and distribution facilities, and gas transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to air and water, and protection of natural resources. We continuously monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are promulgated, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, the majority of our environmental reserve relates to the remediation of former manufactured gas plant (MGP) sites owned by us. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions, therefore, while remediation exposure exists, it may be many years before costs become fixed and reliably determinable.

Our liability for environmental remediation obligations is estimated to range between $22.4 million to $44.1 million. As of March 31, 2010, we have a reserve of approximately $31.8 million. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. Over time, as specific laws are implemented and we gain experience in operating under them, a portion of the costs related to such laws will become determinable, and we may seek authorization to recover such costs in rates or seek insurance reimbursement as applicable; therefore, we do not expect these costs to have a material adverse effect on our consolidated financial position or ongoing operations. There can be no assurance, however, of regulatory recovery.

Global Climate Change

We have a joint ownership interest in four electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. In addition, a significant portion of the electric supply we procure in the market is generated by coal-fired plants.

There is a growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation at the federal level, actions at the state level, as well as litigation relating to greenhouse gas emissions.

Specifically, coal-fired plants have come under scrutiny due to their emissions of carbon dioxide, and in September 2009, the U.S. Court of Appeals for the Second Circuit reversed a federal district court's decision and ruled that several states and public interest groups could sue five electric utility companies under federal common law for allegedly causing a public nuisance as a result of their emissions of greenhouse gases. In October 2009, the U.S. Court of Appeals for the Fifth Circuit reversed a federal district court and ruled that individuals damaged by Hurricane Katrina could sue a variety of companies that emit carbon dioxide, including electric utilities, for allegedly causing a public nuisance that contributed to their damages. Additional litigation in federal and state courts over these issues is continuing.

In addition to litigation during 2009, the Environmental Protection Agency (EPA) issued a finding that greenhouse gas emissions endanger the public health and welfare. The EPA's finding indicated that the current and projected levels of six greenhouse gas emissions – carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride contribute to climate change. In a related matter, the EPA also proposed rules that would require all new or modified "stationary sources," such as power plants, that emit 25,000 tons of greenhouse gases per year to obtain permits incorporating the "best available control technology" for such emissions.

In September 2009, the EPA announced the adoption of the first comprehensive national system for reporting emissions of carbon dioxide and other greenhouse gases produced by major sources in the United States. The new reporting requirements will apply to suppliers of fossil fuel and industrial chemicals, manufacturers of motor vehicles and engines, as well as large direct emitters of greenhouse gases with emissions equal to or greater than a threshold of 25,000 metric tons per year, which includes certain of our facilities. The effective date for gathering the data is January 2010 with the first mandatory reporting due in March 2011.

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, a bill introduced by Rep. Henry Waxman and Rep. Edward Markey and popularly known as the Waxman-Markey bill. The bill would regulate greenhouse gas emissions by instituting a cap-and-trade-system, in which an economy-wide cap on U.S. greenhouse gas emissions would be established starting in 2012 with a cap 3% below the baseline 2005 level. The cap would steeply decline over time until in 2050 it reaches 83% below the baseline level. Emission allowances, which are rights to emit greenhouse gases, would be both allocated for free and auctioned. In addition, the draft legislation contains a renewable energy standard of 25% by the year 2025 and an energy efficiency mandate for electric and natural gas utilities, as well as other requirements. Pending in the U.S. Senate is the Clean Energy Jobs and American Power Act introduced by Sens. John Kerry and Barbara Boxer, known as the Kerry-Boxer bill. The Kerry-Boxer bill also proposes to regulate greenhouse gas emissions by instituting a cap-and-trade-system, with primarily the same target levels proposed by the Waxman-Markey bill; however, the Kerry-Boxer bill is more aggressive in its 2020 target – a reduction to 20% below 2005 levels by 2020 (versus 17% in Waxman-Markey). Although the Waxman-Markey bill is widely viewed as the most probable climate change bill to be enacted into law, the prospects for passage of a similar bill by the U.S. Senate are uncertain.

Other nations have agreed to regulate emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol," an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. At the end of 2009, an international conference to develop a successor to the Kyoto Protocol issued a document known as the Copenhagen Accord. Pursuant to the Copenhagen Accord, the United States submitted a greenhouse gas emission reduction target of 17% compared to 2005 levels.

The Montana Governor's office has joined the Western Regional Climate Initiative (WCI) and is expected to participate in any greenhouse gas emission control regulations that are adopted by the WCI. The WCI, which has a goal of reducing carbon dioxide emissions 15% below the 2005 levels by 2020, currently is developing greenhouse gas emission allocations, offsets, and reporting recommendations.

While we cannot predict the impact of any legislation until final, if legislation or regulations are passed at the federal or state levels imposing mandatory reductions of carbon dioxide and other greenhouse gases on generation facilities, the cost to us and / or our customers could be significant. We are proactively involved in analyzing the impacts of current legislative efforts on our customers and shareholders and are participating in public policy forums related to these issues.

There is a gap between proposed emissions reduction levels and the current capabilities of technology, as there is no currently available commercial scale technology that would achieve the proposed reduction levels. Such technology may not be available within a timeframe consistent with the implementation of climate change legislation or at all. To the extent that such technology does become available, we can provide no assurance that it will be suitable or cost-effective for installation at the generation facilities in which we have a joint interest. We believe future legislation and regulations that affect carbon dioxide emissions from power plants are likely, although technology to efficiently capture, remove and sequester carbon dioxide emissions is not presently available on a commercial scale.

The proposed regulations and/or current litigation related to global climate change could have a material impact on our future capital expenditures and results of operations, but the costs are not determinable at this time. Our current capital expenditures projections do not include significant amounts related to environmental projects. We believe the cost of purchasing carbon emissions credits, or alternatively the proceeds from the sale of any excess carbon emissions credits would be included in our supply trackers and passed through to customers.

Clean Air Act - The Clean Air Act Amendments of 1990 and subsequent amendments stipulate limitations on sulfur dioxide and nitrogen oxide emissions from coal-fired power plants and motor vehicles. We comply with existing emission requirements through purchase of sub-bituminous coal, and we believe that we are in compliance with all presently applicable environmental protection requirements and regulations.

The endangerment finding also allows the EPA to regulate emissions from new light-duty vehicles under the Clean Air Act, which were finalized in March 2010. With the finalization of the regulation of greenhouse gases from light-duty vehicles, greenhouse gas emissions are subject to review under the Clean Air Act's Prevention of Significant Deterioration (PSD) (construction or modification of major sources) permit program. Sources subject to a PSD review for greenhouse gases would be required to use best available control technology to control greenhouse gas emissions.

Regional Haze and Visibility - The Clean Air Visibility Rule was issued by the EPA in June 2005, to address regional haze or regionally-impaired visibility caused by multiple sources over a wide area. The rule requires the use of Best Available Retrofit Technology (BART) for certain electric generating units to achieve emissions reductions from designated sources that are deemed to contribute to visibility impairment in Class I air quality areas. We have a 23.4% interest in Big Stone, a coal-fired power plant located in northeastern South Dakota, which is potentially subject to emission reduction requirements. At the request of the South Dakota Department of Environment and Natural Resources (DENR), the plant operator submitted a model to the DENR in order to evaluate the impact of plant emissions on Class I air quality areas. On September 18, 2009 the DENR approved the modeling protocol and on November 2, 2009 the plant operator submitted to the DENR its analysis of what control technology should be considered BART for nitrogen oxides, sulfur dioxide, and particulate matter for the Big Stone plant. On January 15, 2010, the DENR provided a copy of South Dakota's draft proposed Regional Haze State Implementation Plan (SIP). South Dakota's draft proposed Regional Haze SIP recommends the sulfur dioxide and particulate matter emission control technology and emission rates that generally followed the plant operator's BART analysis. The DENR recommended a Selective Catalytic Reduction technology for nitrogen oxide emission reduction instead of the plant operator recommended separated over-fire air. The estimated capital expenditures for the BART technologies based on the DENR proposal are approximately \$200 - \$300 million for Big Stone (our share would be 23.4%). The DENR proposes to require that BART be installed and operating as expeditiously as practicable, but no later than five years from EPA's approval of the South Dakota Regional Haze SIP, which is expected no later than January 15, 2011. If the emissions reduction technology is required, we will seek to recover these costs through the ratemaking process. The South Dakota Public Utilities Commission (SDPUC) has allowed the recovery on a timely basis of the costs of environmental improvements; however, there is no precedent on a project of this size.

Clean Air Mercury Rule - In March 2005, the EPA issued the Clean Air Mercury Regulations (CAMR) to reduce the emissions of mercury from coal-fired facilities through a market-based cap-and-trade program. Although the U.S. Court of Appeals for the District of Columbia Circuit struck down CAMR, the state of Montana finalized its own mercury emission rules that require, by 2010, every coal-fired generating plant in Montana to achieve reductions more stringent than CAMR's 2018 requirements. Chemical injection technologies were installed at Colstrip during the fourth quarter of 2009 to meet these requirements. If the enhanced chemical injection technologies are not sufficient to meet the required levels of reduction, then adsorption/absorption technology with fabric filters would be required, which could represent a material cost. We are continuing to work with the other Colstrip owners to assess compliance with these reduction levels.

Manufactured Gas Plants

Approximately \$26.5 million of our environmental reserve accrual is related to manufactured gas plants. A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently investigating, characterizing, and initiating remedial actions at the Aberdeen site pursuant to work plans approved by the South Dakota DENR. In 2007, we completed remediation of sediment in a short segment of Moccasin Creek that had been impacted by the former manufactured gas plant operations. Our current reserve for remediation costs at this site is approximately \$12.8 million, and we estimate that approximately \$10 million of this amount will be incurred during the next five years.

We also own sites in North Platte, Kearney and Grand Island, Nebraska on which former manufactured gas facilities were located. During 2005, the Nebraska Department of Environmental Quality (NDEQ) conducted Phase II investigations of soil and groundwater at our Kearney and Grand Island sites. In 2006, the NDEQ released to us the Phase II Limited Subsurface Assessment performed by the NDEQ's environmental consulting firm for Kearney and Grand Island. We have conducted limited additional site investigation, assessment and monitoring work at Kearney and Grand Island. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

In addition, we own or have responsibility for sites in Butte, Missoula and Helena, Montana on which former manufactured gas plants were located. An investigation conducted at the Missoula site did not require entry into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program, but required preparation of a groundwater monitoring plan. The Butte and Helena sites were placed into the MDEQ's voluntary remediation program for cleanup due to excess regulated pollutants in the groundwater. We have conducted additional groundwater monitoring at the Butte and Missoula sites and, at this time, we believe natural attenuation should address the conditions at these sites; however, additional groundwater monitoring will be necessary. In Helena, we continue limited operation of an oxygen delivery system implemented to enhance natural biodegradation of pollutants in the groundwater and we are currently evaluating limited source area treatment/removal options. Monitoring of groundwater at this site is ongoing and will be necessary for an extended time. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action at the Helena site or if any additional actions beyond monitored natural attenuation will be required.

Other

We continue to manage equipment containing polychlorinated biphenyl (PCB) oil in accordance with the EPA's Toxic Substance Control Act regulations. We will continue to use certain PCB-contaminated equipment for its remaining useful life and will, thereafter, dispose of the equipment according to pertinent regulations that govern the use and disposal of such equipment.

We routinely engage the services of a third-party environmental consulting firm to assist in performing a comprehensive evaluation of our environmental reserve. Based upon information available at this time, we believe that the current environmental reserve properly reflects our remediation exposure for the sites currently and previously owned by us. The portion of our environmental reserve applicable to site remediation may be subject to change as a result of the following uncertainties:

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and
- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

LEGAL PROCEEDINGS

Colstrip Energy Limited Partnership

In December 2006 and June 2007, the MPSC issued orders relating to certain QF rates for the period July 1, 2003 through June 30, 2006. Colstrip Energy Limited Partnership (CELP) is a QF with which we have a power purchase agreement through June 2024. Under the terms of the power purchase agreement with CELP, energy and capacity rates were fixed through June 30, 2004 (with a small portion to be set by the MPSC's determination of rates in the annual avoided cost filing), and beginning July 1, 2004 through the end of the contract, energy and capacity rates are to be determined each year pursuant to a formula, with the rates to be used in that formula derived from the annual MPSC QF rate review. CELP initially appealed the MPSC's orders and then, in July 2007, filed a complaint against NorthWestern and the MPSC in Montana district court, which contested the MPSC's orders. CELP disputed inputs into the underlying rates used in the formula, which initially are calculated by us and reviewed by the MPSC on an annual basis, to calculate energy and capacity payments for the contract years 2004-2005 and 2005-2006. CELP claimed that NorthWestern breached the power purchase agreement causing damages, which CELP asserted to be approximately $23 million for contract years 2004-2005 and 2005-2006. The parties stipulated that NorthWestern would not implement the final derived rates resulting from the MPSC orders, pending an ultimate decision on CELP's complaint. The Montana district court, on June 30, 2008, granted both a motion by the MPSC to bifurcate, having the effect of separating the issues between contract/tort claims against us and the administrative appeal of the MPSC's orders and a motion by us to refer the claims against us to arbitration. The order also stayed the appellate decision pending a decision in the arbitration proceedings. Arbitration was held in June 2009 and the arbitration panel entered its interim award in August 2009, holding that although NorthWestern failed to use certain data inputs required by the power purchase agreement, CELP was entitled to neither damages for contract years 2004-2005 or 2005-2006, nor to recalculation of the underlying MPSC filings for those years, effectively finalizing CELP's contract rates for those years. We requested clarification from the arbitration panel as to its intent regarding the applicable rates. On November 2, 2009, we received the final award from the arbitration panel which confirmed that the filed rates for 2004-2005 and 2005-2006 are not required to be recalculated. In affirming its interim award, the arbitration panel also denied CELP's request for attorney fees, holding that each party would be responsible for its own fees. The final arbitration panel award is pending confirmation by the Montana district court, which held a hearing on April 9, 2010 and asked the parties to submit proposed orders by May 7, 2010. If confirmed, the arbitration award will require us to refile with the MPSC for a new determination of rates subsequent to June 30, 2006 using data inputs required by the power purchase agreement. CELP continues to dispute the results of the arbitration award, and due to the uncertainty around the resolution we are currently unable to predict the outcome of this matter.

Gonzales

We are a defendant – along with our predecessor entities the Montana Power Company (MPC) and pre-bankruptcy NorthWestern Corporation (NOR) – in an action (Gonzales Action) pending in the Montana Second Judicial District Court, Butte-Silver Bow County (Montana State Court), alleging fraud, constructive fraud and violations of the Unfair Claim Settlement Practices Act all arising out of the adjustment of workers' compensation claims. Putnam and Associates, the third party administrator of such workers' compensation claims, also is a defendant.

The Gonzales Action was first filed on December 18, 1999, against MPC (NOR acquired MPC in 2002) and was stayed due to the Chapter 11 bankruptcy filing of NOR. On August 10, 2005, the Bankruptcy Court approved a "Bankruptcy Settlement Stipulation" which permitted the Gonzales Action to proceed, assigned to plaintiffs NOR's interest in MPC's insurance policies (to the extent applicable to the allegations made by plaintiffs), released NOR from any and all obligations to the plaintiffs concerning such claims, and preserved plaintiffs' right to pursue claims arising after November 1, 2004, relating to the adjustment of workers' compensation claims. To date, no insurance carrier has indicated that coverage is available for any of the claims.

On September 30, 2009, the Montana State Court granted the plaintiffs' motions to file a sixth amended complaint and partially granted the plaintiff's motion for class certification. The Montana State Court excluded the fraud claims from its class certification. The new complaint seeks to hold us jointly and severally liable for the acts of MPC and NOR and alleges that we negligently/intentionally sabotaged plaintiffs' ability to recover under the MPC insurance policies. Plaintiffs seek compensatory and punitive damages from all defendants. Due to the individual nature of the claims, we believe the class certification was improper under Montana law, and we continue to believe that the new complaint violates the bankruptcy stipulation. We have filed an appeal to the Supreme Court of the State of Montana with respect to these issues and intend to continue to defend the lawsuit vigorously. We also believe the sixth amended complaint violates the Bankruptcy Settlement Stipulation and have filed a motion with the Bankruptcy Court seeking enforcement of the Bankruptcy Settlement Stipulation. The motion before the Bankruptcy Court is pending. In addition, settlement discussions concerning these claims are ongoing.

Maryland Street

On March 16, 2009, Monsignor John F. McCarthy, the duly appointed personal representative for the Estate of Father James C. McCarthy, filed a lawsuit against NorthWestern and one of our employees in the District Court of Butte-Silver Bow County, Montana for injuries that Fr. McCarthy received in an April 2007 natural gas explosion that destroyed his four-plex residence. The complaint alleges negligence and strict liability with respect to the maintenance and operation of the natural gas distribution system that served the residence. Fr. McCarthy died in November 2007, allegedly because of injuries sustained in the explosion. The plaintiff seeks unspecified compensatory and punitive damages and other equitable relief, costs and attorney's fees. The investigation of this incident is ongoing, and while we cannot predict an outcome, we intend to continue vigorously defending against the lawsuit.

Bozeman Explosion

On March 5, 2009, a natural gas explosion occurred in downtown Bozeman, Montana. The explosion resulted in one fatality, the destruction of or damage to several buildings and the businesses in them, and damage to other nearby properties and businesses. Twenty lawsuits have been filed against NorthWestern to date in the District Court of Gallatin County, Montana and a number of claims have been made. Our total available insurance coverage is approximately $150 million for known and potential claims. We have paid our deductible under these policies and our insurance carrier has assumed the defense and handling of the existing and anticipated future lawsuits and claims.

McGreevey Litigation

We are one of several defendants in a class action lawsuit entitled McGreevey, et al. v. The Montana Power Company, et al., now pending in U.S. District Court in Montana. The lawsuit, which was filed by former shareholders of The Montana Power Company (most of whom became shareholders of Touch America Holdings, Inc. (Touch America) as a result of a corporate reorganization of The Montana Power Company), contends that the disposition of various generating and energy-related assets by The Montana Power Company are void because of the failure to obtain shareholder approval for the transactions. Plaintiffs thus seek to reverse those transactions, or receive fair value for their stock as of late 2001, when plaintiffs claim shareholder approval should have been sought. NorthWestern is named as a defendant due to the fact that we purchased The Montana Power Company L.L.C. (now Clark Fork and Blackfoot LLC), which plaintiffs claim is a successor to The Montana Power Company.

In October 2009, the parties reached a global settlement, which must be approved by the U.S. District Court in Montana and the Delaware Bankruptcy Court. In November 2009, the parties submitted documentation concerning the settlement to the U.S. District

Court in Montana for its approval. Approval of the settlement by the U.S. District Court in Montana is still pending. In February 2010, the parties submitted documentation concerning the settlement to the Delaware Bankruptcy Court, which approved the settlement on February 23, 2010. A fairness hearing concerning the proposed settlement is scheduled for May 2010 with the U.S. District Court in Montana. If the court approves the settlement, we will receive approximately $2.0 million from the Touch America bankruptcy estate and have no remaining exposure in the litigation.

Sierra Club

On June 10, 2008, Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) (South Dakota Federal District Court) against us and two other co-owners (the Defendants) of Big Stone Generating Station (Big Stone). The complaint alleged certain violations of the (i) Prevention of Significant Deterioration and (ii) New Source Performance Standards (NSPS) provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleged that the Defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. Sierra Club alleged that Defendants' actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. Sierra Club sought both declaratory and injunctive relief to bring the Defendants into compliance with the Clean Air Act and the South Dakota SIP and to require Defendants to remedy the alleged violations. Sierra Club also sought unspecified civil penalties, including a beneficial mitigation project. We believe these claims are without merit and that Big Stone was and is being operated in compliance with the Clean Air Act and the South Dakota SIP.

The Defendants filed a Motion to Dismiss the Sierra Club complaint on August 12, 2008, based on certain of the claims being barred by statute of limitations and the remaining claims being an impermissible collateral attack on valid Clean Air Permits issued by the state of South Dakota. On March 31, 2009, the South Dakota Federal District Court entered a Memorandum Opinion and Order granting Defendants' Motion to Dismiss the Sierra Club Complaint. On July 30, 2009, Sierra Club appealed the South Dakota Federal District Court's decision to dismiss the complaint. On October 13, 2009, the United States Department of Justice (USDOJ) filed a motion seeking a 30-day extension of the time to file an amicus brief in support of the Sierra Club's position. The Court of Appeals granted this motion, as well as our subsequent joint motion with the Sierra Club, extending the timeline. In accordance with the revised briefing schedule, the Sierra Club filed its brief on October 14, 2009, the USDOJ filed its amicus brief on November 24, 2009, we filed our brief on December 24, 2009 (the state of South Dakota served an amicus brief in support of our position on December 30, 2009), and on January 22, 2010, the Sierra Club filed its reply brief. Additionally, on March 15, 2010, we filed correspondence with the court submitting recent supplemental authority in support of our positions, to which the Sierra Club and USDOJ also submitted replies. Appellate briefing has concluded, and oral arguments are scheduled for May 11, 2010.

We are also subject to various other legal proceedings, governmental audits and claims that arise in the ordinary course of business. In the opinion of management, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

(19) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of these shares, 2,265,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 13.

Repurchase of Common Stock

On May 23, 2008, we announced plans to initiate a share buyback program for approximately 3.1 million shares, which is equal to the number of shares in the disputed claims reserve established under our Plan of Reorganization that was confirmed by the bankruptcy court in 2004. We purchased 1.9 million shares from the disputed claims reserve and the remaining shares were purchased using privately negotiated transactions, at our discretion. The actual number and timing of share purchases were subject to market conditions, restrictions related to price, volume, timing, and applicable SEC rules. The total aggregate purchase price was approximately $77.7 million.

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 30,684 and 41,289 during the years ended December 31, 2009 and 2008, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

Sch. 19	MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Intangible Plant**			
2	2301 Organization	$12,873	$12,873	0.00%
3	2302 Franchises and Consents	114,169	114,169	0.00%
4	2303 Miscellaneous Intangible Plant	1,889,692	1,816,958	4.00%
5	**Total Intangible Plant**	2,016,734	1,944,000	3.74%
6				
7	**Underground Storage Plant**			
8	2350 Land and Land Rights	4,587,018	4,459,907	2.85%
9	2351 Structures and Improvements	3,030,416	3,027,231	0.11%
10	2352 Wells	7,810,737	7,807,401	0.04%
11	2353 Lines	8,218,844	7,942,838	3.47%
12	2354 Compressor Station Equipment	7,266,646	7,313,518	-0.64%
13	2355 Measuring & Regulating Equip.	2,953,619	2,923,787	1.02%
14	2356 Purification Equipment	206,563	225,030	-8.21%
15	2357 Other Equipment	867,069	853,905	1.54%
16	**Total Underground Storage Plant**	34,940,912	34,553,617	1.12%
17				
18	**Transmission Plant**			
19	2365 Rights of Way	7,522,087	7,417,710	1.41%
20	2366 Structures and Improvements	11,061,688	9,889,933	11.85%
21	2367 Mains	182,328,100	177,210,958	2.89%
22	2368 Compressor Station Equipment	18,294,127	18,237,948	0.31%
23	2369 Meas. & Reg. Station Equipment	15,064,605	13,262,575	13.59%
24	2370 Communication Equipment	-	-	-
24	2371 Other Equipment	75,019	75,019	0.00%
25	**Total Transmission Plant**	234,345,626	226,094,143	3.65%
26				
27	**Distribution Plant**			
28	2374 Land and Land Rights	904,311	902,556	0.19%
29	2375 Structures and Improvements	90,524	71,404	26.78%
30	2376 Mains	104,048,874	99,633,481	4.43%
31	2377 Compressor Station Equipment	-	-	-
32	2378 M&R Station Equip.-General	2,907,036	2,706,814	7.40%
33	2379 M&R Station Equip.-City Gate	-	-	-
34	2380 Services	58,550,590	57,790,227	1.32%
35	2381 Customers Meters and Regulators	52,628,006	49,921,253	5.42%
36	2382 Meter Installations	-	-	-
37	2383 House Regulators	-	-	-
38	2384 House Regulator Installations	-	-	-
39	2385 M&R Station Equip.-Industrial	56,334	56,334	0.00%
40	2386 Other Prop. on Customers' Premises	-	-	-
41	2387 Other Equipment	26,216	26,216	0.00%
42	**Total Distribution Plant**	219,211,891	211,108,285	3.84%

Sch. 19	cont. MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1				
2	**General Plant**			
3	2389 Land and Land Rights	101,675	101,675	0.00%
4	2390 Structures and Improvements	707,791	707,791	0.00%
5	2391 Office Furniture and Equipment	210,464	159,409	32.03%
6	2392 Transportation Equipment	6,816,622	6,120,066	11.38%
7	2393 Stores Equipment	6,601	7,507	-12.07%
8	2394 Tools, Shop & Garage Equipment	4,163,699	3,615,320	15.17%
9	2395 Laboratory Equipment	823,905	818,417	0.67%
10	2396 Power Operated Equipment	1,937,761	1,927,961	0.51%
11	2397 Communication Equipment	1,934,450	1,834,188	5.47%
12	2398 Miscellaneous Equipment	76,853	80,198	-4.17%
13	2399 Other Tangible Property	-	-	-
14	**Total General Plant**	16,779,821	15,372,532	9.15%
15	**Total Gas Plant in Service**	507,294,984	489,072,577	3.73%
16				
17	4101 Gas Plant Allocated from Common	30,852,095	30,606,804	0.80%
18	2105 Gas Plant Held for Future Use	4,900	4,900	0.00%
19	2107 Gas Construction Work in Progress	5,518,699	4,132,850	33.53%
20	2117 Gas in Underground Storage	51,729,271	74,458,593	-30.53%
21				
22				
23	**TOTAL GAS PLANT**	$595,399,949	$598,275,724	-0.48%
24				
25				
26	**CONSOLIDATED**	December 31,		
27	**PLANT IN SERVICE**	2009	2008	
28				
29	Montana Electric (Includes CU4 in 2009)	$ 1,866,461,607	$ 1,394,151,266	
30	Yellowstone National Park	12,140,958	11,699,040	
31	Colstrip Unit 4	-	87,205,999	
32	Montana Natural Gas (Includes CMP)	507,294,984	489,072,577	
33	Common	93,059,655	92,523,261	
34	Townsend Propane	1,505,229	1,500,355	
35	South Dakota Electric	421,377,251	409,396,824	
36	South Dakota Natural Gas	138,114,916	135,070,061	
37	South Dakota Common	36,060,546	42,027,354	
38	Asset Retirement Obligation	5,317,420	6,269,604	
39	**TOTAL PLANT**	$ 3,081,332,566	$ 2,668,916,341	

Sch. 20	MONTANA DEPRECIATION SUMMARY - NATURAL GAS (INCLUDES CMP)				
	Functional Plant Class	Montana Plant Cost	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Production and Gathering	$ -	$ -	$ -	-
4					
5	Underground Storage	34,542,365	19,865,372	19,347,679	1.72%
6					
7	Other Storage	-	-	-	-
8					
9	Transmission	225,376,914	82,800,170	79,143,947	1.73%
10					
11	Distribution	210,950,229	96,654,797	90,842,118	2.68%
12					
13	General and Intangible	17,010,602	9,577,288	8,843,134	6.75%
14					
15	Common	29,612,071	16,197,396	14,886,267	7.88%
16					
17					
18	**Total Accum Depreciation**	$517,492,181	$225,095,023	$213,063,145	2.32%
19					
20					
21					

		December 31,	
22	**Consolidated**		
23	**Accumulated Depreciation**	2009	2008
24			
25	Montana Electric (Includes CU4 in 2009)	$717,960,200	$652,606,520
26	Yellowstone National Park	8,054,870	7,755,794
27	Colstrip Unit 4	-	38,674,170
28	Montana Natural Gas (Includes CMP)	208,897,627	198,176,878
29	Common	47,361,448	43,541,925
30	Townsend Propane	564,216	521,410
31	South Dakota Electric	227,069,266	217,665,844
32	South Dakota Natural Gas	57,010,774	53,212,037
33	South Dakota Common	8,154,467	15,161,327
34	Acquisition Writedown	88,826,859	115,982,411
35	Basin Creek Capital Lease	7,036,640	5,026,172
36	FIN 47	624,602	403,740
37	CWIP-Capital Retirement Clearing	-1,904,064	-589,906
38	**Total Consolidated Accum Depreciation**	$1,369,656,905	$1,348,138,322

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - NATURAL GAS			
	Account Number & Title	This Year Montana	Last Year Montana	%Change
1				
2	154 Plant Materials & Operating Supplies			
3	Assigned and Allocated to:			
4	Operation & Maintenance	-	-	-
5	Construction	-	-	-
6	Storage Plant	$ 122,674	$ 141,555	-13.34%
7	Transmission Plant	822,762	926,235	-11.17%
8	Distribution Plant	1,592,764	2,028,418	-21.48%
9				
10	**Total MT Materials and Supplies**	$2,538,200	$3,096,208	-18.02%
11		-		
12				

13	**Consolidated**	December 31,	
14	**Materials and Supplies**	2009	2008
15			
16	Montana Natural Gas	$2,538,200	$3,096,208
17	Montana Electric (including CU4 in 2009)	12,315,736	9,607,588
18	Colstrip Unit 4	-	1,666,828
19	South Dakota	5,325,772	4,937,004
20			
21	**Total Consolidated Materials and Supplies**	$20,179,708	$19,307,628

Sch. 22 MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - NATURAL GAS

Commission Accepted - Most Recent 1/	% Capital Structure	% Cost Rate	Weighted Cost
Docket Number: 2000.8.113			
Order Number : 6271c			
Common Equity	45.00%	10.75%	4.84%
Preferred Stock	6.97%	6.40%	0.45%
QUIPS Preferred	7.86%	8.54%	0.67%
Long Term Debt	40.17%	7.13%	2.86%
Other			
TOTAL	100.00%		8.82%

NorthWestern Corporation Consolidated	% Capital Structure	% Cost Rate 2/	Weighted Cost
Common Equity	44.51%	10.75%	4.78%
Preferred Stock	0.00%	0.00%	0.00%
QUIPS Preferred	0.00%	0.00%	0.00%
Long Term Debt	55.49%	6.03%	3.35%
Other			
TOTAL	100.00%		8.13%

1/ Docket 2000.8.113, Order 6271c specifies the authorized capital structure and associated costs for the regulated gas utility effective May 8, 2001.

2/ The cost of debt represents Montana jurisdiction only, as reflected on Schedule 24.

Sch. 23

STATEMENT OF CASH FLOWS

Description	This year	Last Year	% Change
Increase/(decrease) in Cash & Cash Equivalents:			
Cash Flows from Operating Activities:			
Net Income	$ 73,420,376	$ 67,601,004	8.61%
Noncash Charges (Credits) to Income:			
Depreciation	84,576,896	79,758,326	6.04%
Amortization, Net	(731,021)	(1,043,731)	29.96%
Other Noncash Charges to Net Income, Net	4,376,377	4,994,829	-12.38%
Deferred Income Taxes, Net	54,138,456	41,424,645	30.69%
Investment Tax Credit Adjustments, Net	(494,074)	(580,189)	14.84%
Change in Operating Receivables, Net	8,474,550	1,389,563	>300.00%
Change in Materials, Supplies & Inventories, Net	23,452,861	(7,197,797)	>300.00%
Change in Operating Payables & Accrued Liabilities, Net	(42,938,219)	11,451,044	>-300.00%
Allowance for Funds Used During Construction (AFUDC)	(2,113,313)	(641,253)	-229.56%
Change in Other Assets & Liabilities, Net	(81,835,027)	(23,159,947)	-253.35%
Other Operating Activities:			
Undistributed Earnings from Subsidiary Companies	5,246,654	(8,683,838)	160.42%
Change in Regulatory Assets	(7,701,447)	20,470,034	-137.62%
Change in Regulatory Liabilities	(6,894,262)	7,180,108	-196.02%
Net Cash Provided by/(Used in) Operating Activities	110,978,807	192,962,798	-42.49%
Cash Inflows/Outflows From Investment Activities:			
Construction/Acquisition of Property, Plant and Equipment	(189,360,461)	(124,562,480)	-52.02%
(Net of AFUDC)			
Proceeds from Sale of Assets	326,250	199,613	63.44%
Other Investing Activities:			
Investments in and Advances to Assoc. and Subsidiary Companies	-	-	0.00%
Distribution from Subsidiaries	-	-	-
Net Cash Provided by/(Used in) Investing Activities	(189,034,211)	(124,362,867)	-52.00%
Cash Flows from Financing Activities:			
Proceeds from Issuance of:			
Long-Term Debt	304,832,500	55,000,000	>300.00%
Credit Facilities Borrowings	348,000,000	96,000,000	262.50%
Long-Term Debt of Subsidiary Companies	-	-	0.00%
Payment for Retirement of:			0.00%
Credit Facilities Repayments	(390,000,000)	-	100.00%
Long-Term Debt	(131,665,019)	(76,350,000)	-72.45%
Long-Term Debt of Subsidiary Companies	-	(13,226,580)	100.00%
Capital Lease Obligations, Net	(273,234)	(1,388,310)	80.32%
Dividends on Common Stock	(48,185,589)	(49,833,215)	3.31%
Other Financing Activities:			
Exercise of Warrants	-	-	-
Debt Financing Costs	(10,824,231)	(1,550,011)	>-300.00%
Treasury Stock Purchases	(740,781)	(78,706,635)	99.06%
Net Cash Provided by (Used in) Financing Activities	71,143,646	(70,054,751)	201.55%
Net Increase/(Decrease) in Cash and Cash Equivalents	(6,911,758)	(1,454,820)	>-300.00%
Cash and Cash Equivalents at Beginning of Year	11,251,439	12,706,259	-11.45%
Cash and Cash Equivalents at End of Year	$ 4,339,680	$ 11,251,439	-61.43%

This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana Pipeline Corporation and the Colstrip 4 79 and 143 MW Trusts.

Sch. 24

MONTANA LONG TERM DEBT 1/

Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
First Mortgage Bonds								
6.34% Series, Due 2019	03/26/09	04/01/19	$250,000,000	$247,657,313	$249,845,062	6.340%	$16,514,170	6.61%
5.71% Series, Due 2039	10/15/09	10/15/39	55,000,000	54,450,119	55,000,000	5.710%	3,158,841	5.74%
6.04% Series, Due 2016	09/13/06	09/01/16	150,000,000	148,302,298	149,951,000	6.040%	9,308,115	6.21%
5.875% Series, Due 2014	11/01/04	11/01/14	161,000,000	161,000,000	161,000,000	5.875%	9,934,663	6.17%
Total First Mortgage Bonds			$616,000,000	$611,409,731	$615,796,062		$38,915,788	6.32%
Pollution Control Bonds								
4.65% Series, Due 2023	04/27/06	08/01/23	$170,205,000	$164,451,956	$170,205,000	4.650%	$8,467,855	4.98%
Total Pollution Control Bonds			$170,205,000	$164,451,956	$170,205,000		$8,467,855	4.98%
Other Long Term Debt								
Other Capital Leases - Fleet Lease	06/30/09	06/30/12	$54,086	$54,086	$24,512		$1,438	1.44%
Total Other Long Term Debt			$54,086	$54,086	$24,512		$1,438	
TOTAL LONG TERM DEBT			$786,259,086	$775,915,772	$786,025,575		$47,385,081	6.03%

1/ Total Capital Leases does not include amounts due within 1 year of $23,291. It also does not include amounts associated with the Basin Creek contract, which totals $36,719,221.

Sch. 25	PREFERRED STOCK									
	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	NOT APPLICABLE									
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
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19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	TOTAL									

Sch. 26	COMMON STOCK							
	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price		Price/ Earnings Ratio
						High	Low	
January	35,930,160	$21.52				$24.85	$21.71	
February	35,936,518	21.72				25.39	19.31	
March	35,936,518	21.55	$0.63	0.335		21.98	18.48	
April	35,939,518	21.60				22.50	20.00	
May	35,941,842	21.70				22.44	20.59	
June	35,941,842	21.39	0.17	0.335		23.49	21.63	
July	35,941,937	21.41				24.87	22.58	
August	35,983,082	21.50				24.94	23.29	
September	35,983,082	21.56	0.53	0.335		24.81	23.17	
October	35,983,109	21.75				25.20	23.61	
November	36,002,928	21.90				25.80	23.78	
December	36,003,434	21.89	0.70	0.335		26.85	25.53	
TOTAL Year End	35,959,588	$21.89	$2.03	1.340	33.99%	$26.02		12.8

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2009.

Sch. 27	MONTANA EARNED RATE OF RETURN - GAS		
Description	This Year	Last Year	% Change
Rate Base			
101 Plant in Service	$527,364,728	$501,042,791	5.25%
108 Accumulated Depreciation	(219,701,851)	(208,260,252)	-5.49%
Net Plant in Service	$307,662,877	$292,782,539	5.08%
Additions:			
154, 156 Materials & Supplies	$4,449,364	$4,234,378	5.08%
165 Prepayments			
Other Additions 1/	33,669,325	33,245,524	1.27%
Total Additions	$38,118,689	$37,479,902	1.70%
Deductions:			
190 Accumulated Deferred Income Taxes	$35,332,755	$27,781,049	27.18%
252 Customer Advances for Construction	10,337,352	10,100,167	2.35%
255 Accumulated Def. Investment Tax Credits			
Other Deductions	37,661,227	37,698,914	-0.10%
Total Deductions	$83,331,334	$75,580,130	10.26%
Total Rate Base	$262,450,232	$254,682,311	3.05%
Adjusted Rate Base	$262,450,232	$254,682,311	3.05%
Net Earnings	$ 19,479,167	$21,533,687	-9.54%
Rate of Return on Average Rate Base	7.422%	8.455%	-12.22%
Rate of Return on Average Equity 2/	7.776%	9.936%	-21.74%
Major Normalizing and Commission Ratemaking Adjustments			
Rate Schedule Revenues	($420,733)	($280,213)	-50.15%
Funding Trust Regulatory Liability	15,911	104,702	-84.80%
2007 Property Tax Refund 3/	-	(1,204,688)	100.00%
Depreciation Related to Stipulation 4/	(426,373)	(215,556)	-97.80%
Non-Allowables:			
Advertising	69,821	161,248	-56.70%
Dues, Contributions, Other	19,964	19,839	0.63%
Associated Income Taxes 5/	697,892	1,178,992	-40.81%
Total Adjustments	($43,518)	($235,675)	81.53%
Revised Net Earnings	$19,435,649	$21,298,012	-8.74%
Rate Base Adjustment			
Stipulation with MCC 4/	($12,697,407)	($6,402,000)	-98.34%
Revised Rate Base	$249,752,825	$248,280,311	0.59%
Adjusted Rate of Return on Average Rate Base	7.782%	8.578%	-9.28%
Adjusted Rate of Return on Average Equity 2/	7.825%	9.527%	-17.87%

1/ Other additions includes a FAS 109 Regulatory Asset that provides an offset to the accumulated deferred taxes.

2/ Return on Equity calculated using the capital structure approved in Docket D2000.8.113.

3/ During December 2008, a property tax refund estimate was booked for taxes from year 2007, net of legal costs.

4/ Per NWE/MCC Stipulation Agreement Docket No. D2007.7.82 reflecting one-third of the $38.8 million allocated to natural gas as a rate base reduction and inclusion of a comparable portion of annual depreciation expense for year 2009.

5/ Associated income taxes include an interest synchronization adjustment based upon the approved capital structure in Docket D2000.8.113.

Sch. 27	cont. MONTANA EARNED RATE OF RETURN - GAS			
	Description	This Year	Last Year	% Change
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset 2/	$57,517	($666,649)	108.63%
4	Gas Stored Underground	32,096,313	32,096,313	0.00%
5	Cost of Refinancing Debt	1,208,226	1,303,746	-7.33%
6	SAP Development Costs	307,269	512,114	-40.00%
8	Total Other Additions	$33,669,325	$33,245,524	1.27%
10	**Detail - Other Deductions**			
11	Personal Injury and Property Damage	$1,265,344	$769,173	64.51%
12	Storage Gas Sales 2000 & 2001	12,722,914	13,143,430	-3.20%
13	Gross Cash Requirements	5,662,545	5,775,887	-1.96%
14	Bond Refinancing CTC - GP	4,298,064	4,298,064	0.00%
15	Bond Refinancing CTC - RA	13,689,232	13,689,232	0.00%
16	MPSC/MCC Taxes	23,128	23,128	0.00%
18	Total Other Deductions	$37,661,227	$37,698,914	-0.10%

Sch. 28	MONTANA COMPOSITE STATISTICS - NATURAL GAS (INCLUDES CMP)		
		Description	Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	$ 538,147,079
5	105	Plant Held for Future Use	4,900
6	107	Construction Work in Progress	5,518,699
7	117	Gas in Underground Storage	51,729,271
8	151-163	Materials & Supplies	2,538,200
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	225,095,023
11	252	Contributions in Aid of Construction	10,299,135
12	**NET BOOK COSTS**		$ 362,543,991
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	$ 232,401,525
17			
18	**Total Operating Revenues**		$ 232,401,525
19			
20	401-402	Other Operating Expenses (including regulatory amortizations)	$ 176,449,850
21	403-407	Depreciation & Amortization Expenses	13,673,834
22	408.1	Taxes Other than Income Taxes	21,543,647
23	409-411	Federal & State Income Taxes	1,255,027
24			
25	**Total Operating Expenses**		$ 212,922,358
26	**Net Operating Income**		$ 19,479,167
27			
28	415-421.1	Other Income	1,631,288
29	421.2-426.5	Other Deductions	258,015
30	**NET INCOME BEFORE INTEREST EXPENSE**		$20,852,440
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	156,698
34		Commercial	21,934
35		Industrial	296
36		Other (including interdepartmental)	145
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		179,073
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Dkt)	84.8
41		Average Annual Residential Cost per (Dkt)	$9.98
42		Average Residential Monthly Bill	$70.51
43			
44		Plant in Service (Gross) per Customer	$3,005

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,234	466	75	2	543
2	Amsterdam	-	55	8	-	63
3	Anaconda	9,417	3,344	320	5	3,669
4	Augusta	284	193	43	1	237
5	Belfry	219	5	-	-	5
6	Belgrade	5,728	5,178	743	1	5,922
7	Big Mountain	-	192	33	-	225
8	Big Sandy	703	292	67	-	359
9	Big Timber	1,650	924	179	9	1,112
10	Bigfork	1,421	1,299	207	-	1,506
11	Billings	89,847	17	3	2	22
12	Bonner	1,693	61	5	-	66
13	Boulder	1,300	478	79	2	559
14	Bozeman	27,509	19,196	3,083	10	22,289
15	Browning	3,877	1,039	159	3	1,201
16	Buffalo	-	5	-	-	5
17	Butte	33,892	12,473	1,387	40	13,900
18	Cardwell	40	16	5	-	21
19	Carter	62	31	9	-	40
20	Chester	871	363	122	3	488
21	Chinook	1,386	699	130	6	835
22	Choteau	1,802	858	171	3	1,032
23	Churchill	-	455	50	-	505
24	Clancy	1,406	691	35	-	726
25	Clinton	-	364	19	1	384
26	Columbia Falls	3,645	3,308	357	4	3,669
27	Columbus	1,748	1,042	153	6	1,201
28	Conrad	2,753	1,132	199	15	1,346
29	Coram	337	112	21	-	133
30	Corvallis	443	1,134	91	-	1,225
31	Cut Bank	3,105	44	11	1	56
32	Deer Lodge	3,421	1,608	204	6	1,818
33	Dillon	3,752	2,034	327	5	2,366
34	Drummond	318	208	53	2	263
35	East Glacier Park	396	128	44	1	173
36	East Helena	1,642	1,968	122	2	2,092
37	Elliston	225	99	13	-	112
38	Essex	-	76	15	1	92
39	Fairfield	659	399	88	4	491
40	Florence	901	1,186	69	1	1,256
41	Floweree	-	43	7	-	50
42	Fort Belknap	1,262	351	55	-	406
43	Fort Benton	1,594	642	153	-	795
44	Fort Harrison	-	-	6	59	65
45	Fort Shaw	274	105	13	-	118
46	Galata	-	3	-	-	3
47	Gallatin Gateway	-	166	40	-	206
48	Garneill	-	7	1	-	8
49	Garrison	112	23	5	-	28
50	Gildford	185	80	28	-	108
51	Great Falls	56,690	946	51	4	1,001

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Greycliff	56	47	6	-	53
2	Hall	-	62	12	-	74
3	Hamilton	3,705	3,891	677	7	4,575
4	Harlem	848	312	64	2	378
5	Harlowton	1,062	528	97	2	627
6	Havre	9,621	4,498	635	9	5,142
7	Helena	45,819	17,177	2,355	32	19,564
8	Hingham	157	84	30	-	114
9	Hungry Horse	934	241	37	-	278
10	Inverness	103	34	13	-	47
11	Jefferson City	295	150	13	2	165
12	Joplin	210	92	25	-	117
13	Judith Gap	164	65	17	-	82
14	Kalispell	14,223	11,652	2,014	17	13,683
15	Kremlin	126	48	13	-	61
16	Laurel	6,255	11	1	-	12
17	Ledger	-	6	-	-	6
18	Lewistown	6,178	2,943	479	12	3,434
19	Livingston	7,348	3,996	564	17	4,577
20	Logan	-	44	5	-	49
21	Lohman	-	3	1	-	4
22	Lolo	3,388	1,543	94	-	1,637
23	Loma	92	42	20	-	62
24	Manhattan	1,396	730	96	1	827
25	Martin City	331	115	15	-	130
26	Milltown	-	72	9	-	81
27	Missoula	57,053	29,359	3,737	50	33,146
28	Montana City	-	717	64	-	781
29	Moore	186	3	-	-	3
30	Philipsburg	914	417	82	-	499
31	Ramsay	-	38	7	-	45
32	Red Lodge	2,177	1,785	267	7	2,059
33	Reedpoint	185	112	17	1	130
34	Roberts	-	162	20	-	182
35	Rocker	-	37	8	-	45
36	Rudyard	275	132	29	-	161
37	Ryegate	-	4	1	-	5
38	Shawmut	-	24	4	-	28
39	Shelby	3,216	9	3	-	12
40	Sheridan	659	411	73	-	484
41	Silver Star	-	19	4	-	23
42	Silverbow	-	4	-	2	6
43	Simms	373	156	17	-	173
44	Somers	556	375	19	-	394
45	Springdale	-	1	-	-	1
46	Stevensville	1,553	1,571	242	5	1,818
47	Sun River	131	107	17	-	124
48	Three Forks	1,728	822	125	1	948
49	Turah	-	112	3	-	115
50	Twin Bridges	400	206	53	-	259

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Valier	498	306	64	4	374
2	Vaughn	701	325	22	1	348
3	Victor	859	468	76	1	545
4	Walkerville	-	243	11	-	254
5	Warm Springs	-	-	1	-	1
6	West Glacier	-	105	38	3	146
7	Whitefish	5,032	3,909	486	4	4,399
8	Whitehall	1,044	685	106	2	793
9	Whitlash	-	2	2	-	4
10	Williamsburg	-	1	-	-	1
11	Willow Creek	209	95	12	-	107
12	Wolf Creek	-	52	30	1	83
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48	**Total**	447,863	156,698	21,990	382	179,070

1/ Customer populations represent an average of the 12 month period from 01/01/09 through 12/31/09.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	2	2
4	Customer Care	107	102	105
5	Finance	125	122	124
6	Regulatory Affairs	25	25	25
7	Retail Operations	570	555	563
8	Wholesale Operations	191	198	195
9	Legal	13	11	12
10				
11				
12				
13				
14				
15				
16				
17	**TOTAL EMPLOYEES**	1,033	1,015	1,024

1/ Consistent with prior years, part time employees have been converted to full-time equivalents. Also, the prior year's counts have been reclassified to be consistent with the current organizational structure.

Sch. 31	MONTANA CONSTRUCTION BUDGET 2010 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3			
4	MT Bozeman Big Sky Meadow Substation 25MVA	$2,850,000	$2,850,000
5	MT Havre Highland Park Substation	1,413,281	1,413,281
6	MT Helena Southside Sub 100KV Breaker	990,337	990,337
7	MT Bozeman Jack Rabbit to Big Sky 161 kV Line	1,200,128	1,200,128
8	MT Missoula Miller Creek #4 Auto Bank Upgrade	2,483,928	2,483,928
9	MT Great Falls 230KV Switchyard	1,326,157	1,326,157
10			
11	All Other Projects < $1 Million Each MT	41,638,014	41,638,014
12	All Other Projects SD	20,478,331	
13	**Total Electric Utility Construction Budget**	72,380,176	51,901,845
14			
15	**Natural Gas Operations**		
16	MT Mainline #1 Compression Addition	3,857,027	3,857,027
17	MT 2009 - 2012 Continuing Pipeline Integrity Projects	2,257,224	2,257,224
18	MT GTS Cobb 16" Replacement	2,559,850	2,559,850
19	SCADA System Replacement	2,089,300	2,089,300
20	MT GTS Shoshone 6" Pipeline Crow Reser Permit Renew	3,300,000	3,300,000
21			
22	All Other Projects < $1 Million Each MT	11,162,847	11,162,847
23	All Other Projects SD/NE	3,586,299	
24	**Total Natural Gas Utility Construction Budget**	28,812,547	25,226,248
25			
26	**Common**		
27	MT Fleet and Equipment replacements	3,700,000	3,700,000
28	IT CIS Upgrade and Consolidation	3,195,968	3,195,968
29	IT AM-FM GIS system	1,051,328	1,051,328
30	All Other Projects < $1 Million Each MT	5,986,118	5,986,118
31	(Includes IT, Communications, Facilities, Cust Serv)		
32	All Other Projects SD/NE	4,349,863	
33			
34	**Total Common Utility Construction Budget**	18,283,277	13,933,414
35			
36	CU4 capital additions - PPL invoice	4,524,000	4,524,000
37			
38	All Other Projects < $1 Million Each	-	-
39			
40			
41			
42	**Total Colstrip Unit 4 Construction Budget**	4,524,000	4,524,000
43	**TOTAL CONSTRUCTION BUDGET**	$124,000,000	$95,585,507

Sch. 32 MONTANA TRANSMISSION, DISTRIBUTION and STORAGE SYSTEMS -NATURAL GAS

Transmission System-Sales and Transportation

		Peak Day of Month		Peak Day Volume (MMBTU's)		Monthly Volumes (MMBTU's)	
	Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
1	January					5,688,316	4,025,979
2	February					4,434,132	3,649,716
3	March					4,543,786	3,692,789
4	April		NOT AVAILABLE 1/			2,905,741	3,198,454
5	May					2,057,007	4,501,428
6	June					1,679,990	3,881,552
7	July					1,481,995	2,973,353
8	August					1,436,663	2,949,172
9	September					1,641,913	2,897,266
10	October					3,316,155	2,350,424
11	November					3,759,327	2,307,571
12	December					6,402,404	2,996,249
13	TOTAL					39,347,429	39,423,953

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16 Distribution System-Sales and Transportation

		Sales Volumes		Transportation Volumes		Monthly Volumes (MMBTU's)	
17		Sales Volumes		Transportation Volumes		Monthly Volumes (MMBTU's)	
18	Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
19	January	3,471,759		101,701		3,573,460	3,471,759
20	February	2,978,092		73,014		3,051,106	2,978,092
21	March	2,545,997		20,804		2,566,801	2,545,997
22	April	2,055,186		67,638		2,122,824	2,055,186
23	May	1,381,897		10,321		1,392,218	1,381,897
24	June	701,524		81,099		782,623	701,524
25	July	512,199		62,865		575,064	512,199
26	August	418,419		30,833		449,252	418,419
27	September	436,762		87,780		524,542	436,762
28	October	998,365		151,673		1,150,038	998,365
29	November	1,872,381		82,974		1,955,355	1,872,381
30	December	2,918,353		50,953		2,969,306	2,918,353
31	TOTAL	20,290,934		821,655		21,112,589	20,290,934

32

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34 Storage System-Sales and Transportation

		Peak Day & Peak Day Vol.		Total Monthly Volumes (MMBTU's)			
35		Peak Day & Peak Day Vol.		Total Monthly Volumes (MMBTU's)			
36		Total Company	Montana	Total Company		Montana	
37	Month	1/	1/	Injection	Withdrawal	Injection	Withdrawal
38	January			406	3,234,182		2,017,176
39	February			131	2,105,471		1,220,523
40	March			20,252	1,751,417		978,114
41	April			746,639	335,159		652,623
42	May			3,264,745	30,679	2,373,011	
43	June			2,657,151	56,133	2,086,178	
44	July			2,168,878	33,306	1,533,759	
45	August			2,893,246	35,078	1,529,388	
46	September			2,117,412	96,745	1,008,978	
47	October			776,961	523,554		280,449
48	November			413,712	1,253,815		1,269,839
49	December			3,941	3,666,976		2,508,718
50	TOTAL			15,063,474	13,122,515	8,531,314	8,927,442

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52 1/ Data is not accumulated on a daily basis, therefore the peak day and peak day volumes are not available.

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Sch. 33	SOURCES OF MONTANA CORE NATURAL GAS SUPPLY				
	Supply Location	Last Year Volumes MMBTU	This Year Volumes MMBTU	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2	Canadian Pipeline	1,481,496		$11.6460	
3	Havre Pipeline	6,064,437		7.6630	
4	Encana Pipeline	8,096,076		7.5690	
	Colorado Interstate Pipleine	288,000		7.6560	
5	Intra Montana Purchase	3,829,514		7.1750	
6	**TOTAL CORE SUPPLY LAST YEAR**	19,759,523		$7.8520	
7					
8	Canadian Pipeline		3,660,617		$8.8575
9	Havre Pipeline		5,869,305		3.4012
10	Encana Pipeline		7,726,843		3.4328
	Colorado Interstate Pipleine		154,983		3.3890
11	Intra Montana Purchase		3,046,069		3.8762
12	**TOTAL CORE SUPPLY THIS YEAR**		20,457,817		$4.5011
13					
14					
15					
16					

Sch. 34

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (Mcf or Dkt)	Achieved Savings (Mcf or Dkt)	Difference
1							
2	2009 Residential Gas DSM Program	$2,064,565	$ 1,035,210	99.43%	71,600	86,527	14,927
3	10-year life						
4							
5							
6							
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20							
21	A program participant is a Montana residential gas customer who installs eligible						
22	energy conservation measures and receives financial incentives/rebates and/or						
23	weatherization measures.						
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**	$2,064,565	$1,035,210	99.43%	71,600	86,527	14,927

Sch. 35	MONTANA CONSUMPTION AND REVENUES - NATURAL GAS					
	Operating Revenues 1/		Dkt Sold 1/		Average Customers	
Description	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
Sales of Natural Gas						
Residential	$ 132,586,199	$ 161,392,590	13,291,750	13,425,659	156,698	155,391
Commercial	66,516,207	81,261,800	6,732,921	6,754,038	21,934	21,704
Industrial Firm	1,650,341	2,406,178	170,086	207,242	296	305
Public Authorities	526,121	671,947	53,199	57,555	86	82
Interdepartmental	477,153	589,300	48,849	51,268	56	58
Sales to Other Utilities 2/	1,576,550	1,783,993	212,201	201,935	3	3
TOTAL SALES	203,332,571	248,105,808	20,509,006	20,697,697	179,073	177,543
	Operating Revenues		Dkt Transported		Average Customers	
	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
Transportation of Gas						
On System Transportation	$ 19,097,716	$ 18,542,047	17,982,307	18,496,520	247	248
Off System Transportation & Storage	608,881	767,377	1,182,714	1,894,424	4	4
Canadian Montana Pipeline	56,938	33,820				
TOTAL TRANSPORTATION	19,763,535	19,343,244	19,165,021	20,390,944	251	252

1/ Revenue and Dkts include unbilled and Canadian Montana Pipeline.

2/ Includes Sales to Other Utilities only, as compared to Schedule 9 which includes all Sales for Resale.

Sch. 36a	Natural Gas Universal System Benefits Programs					
	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (Dkt)	Most recent program evaluation
1	Local Conservation					
2	E+ Residential Audit	971,500	-	971,500	48,318	2007
3	NWE Promotion	36,918	-	36,918		
4	NWE Labor	24,199	-	24,199		
5	NWE Admin. Non-labor	12,214	-	12,214		
6	USB Interest & Svc Chg	(604)	-	(604)		
7	Market Transformation					
8	Research & Development					
9	Low Income					
10	Bill Assistance	1,564,837	-	1,564,837		
11	Free Weatherization	1,313,178	-	1,313,178	29,408	2007
12	Energy Share	336,000	-	336,000		
14	NWE Promotion	2,419.71	-	2,420		
15	NWE Labor	25,423	-	25,423		
16	NWE Admin. Non-labor	394	-	394		
17	USB Interest & Svc Chg	(2,131)	-	(2,131)		
18	Total	$ 4,284,347	$ -	$ 4,284,347	77,726	
19	Number of customers that received low income rate discounts				8,574	
20	Average monthly bill discount amount ($/mo)				$ 30.42 *(a)*	
21	Average LIEAP-eligible household income				n/a	
22	Number of customers that received weatherization assistance				639 *(b)*	
23	Expected average annual bill savings from weatherization				46 Dkt	
24	Number of residential audits performed				5,288 *(b)*	
25	*(a)* Average monthly bill discount is for the six (6) month time period that the natural gas rate discount is in effect.					
26	*(b)* Total includes combination of electric and natural gas USB funds.					
27	*Note: As part of Order 6679e that MPSC issued December 2008; natural gas USB funding was increased so that electric USB funds are no longer required to cover a portion of the natural gas low income discount.*					

Sch. 36b	Montana Conservation & Demand Side Management Programs					
	Program Description (These are Gas USB Programs)	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (dKt)	Most recent program evaluation
1	Local Conservation					
2	E+ Energy Audit for the Home (Natural Gas)	$ 975,040	$ -	$ 975,040	48,318	2007
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4						
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6						
7						
8	Demand Response					
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15	Market Transformation					
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22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30	Free Weatherization (Natural Gas)	$ 1,313,178	$ -	$ 1,313,178	29,408	2007
31						
32						
33						
34						
35	Other					
36						
37						
38						
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48	Total	$ 2,288,218	$ -	$ 2,288,218	77,726	